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COST OF CONTROLLING DIRECTLY EMITTED ACIDIC EMISSIONS FROM MAJOR INDUSTRIAL SOURCES

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NOTICE

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ABSTRACT

The objectives of this study were: 1) to identify and characterize stationary combustion and industrial sources of directly emitted acidic materials in the United States; 2) to evaluate the technical feasibility of control techniques for these sources; and 3) to estimate the costs of applying these control technologies. Sources of directly emitted acidic materials were identified via a literature search. For most source categories, emissions were estimated using emission factors and combustion and process capacities found in the literature. To focus project funding on source categories with the greatest emissions, model units were developed for those sources which emit 4,500 Mg (5,000 tons) or more of acidic material per year. These model units were then used as bases to establish control techniques and determine control costs. Utility and industrial boilers are the largest U. S. sources, emitting approximately 760,000 Mg (830,000 tons) and 180,000-250,000 Mg (200,000-275,000 tons) of acidic material per year, respectively. Total direct emissions of acidic materials represent an estimated two percent of annual acid precipitation precursor (SO_2, NO_x, and VOC) emissions from stationary sources. The greatest obstacle in this study was the lack of available performance data for acidic emissions control systems. Thus, the control systems chosen for model development and cost estimation are generally those which are commercially demonstrated for control of SO_2 and NO_x and provide the greatest potential for control of acidic material emissions. Promising research and development activities relevant to acidic materials control were also examined.

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ABBREVIATIONS AND SYMBOLS

ACFM	actual cubic feet per minute
bbl	barrel
Btu	British thermal unit
C	Celcius
cm	centimeter
DOE	Department of Energy
F	Fahrenheit
FGD	flue gas desulfurization
ft	feet
GJ	gigajoule
HCl	hydrogen chloride
HF	hydrogen fluoride
hr	hour
H_2S	hydrogen sulfide
kg	kilogram
kJ	kilojoule
kPa	kilopascal
lb	pound
LT	long ton (equal to one megagram)
m	metal
Mg	megagram
mg	milligram
min	minute
MMBtu	million Btu
NO_x	nitrogen oxides
PC	pulverized coal
ppmv	parts per million (by volume)
psi	pounds per square inch
s	second
SCFD	standard cubic feet per day
sd	stream day
SO_x	sulfur oxides
SO_2	sulfur dioxide
TPD	tons per day
VOC	volatile organic compounds

1.0 INTRODUCTION

The Acid Precipitation Act of 1980 established an Interagency Task Force to develop a comprehensive research program for investigation of acid precipitation issues. The National Acid Precipitation Assessment Program (NAPAP) was subsequently established to develop the necessary data and provide a framework for policy recommendations in regard to acid precipitations. One aspect of the overall acid deposition issue is to understand the role and significance of direct emissions of acidic materials. As such, it is necessary to identify the major industrial sources of direct emissions of acidic material (e.g., sulfates, chlorides) and to evaluate the control of these materials. In addition, it is important to know if the most cost-effective methods for reducing acidic emissions differ from those for controlling acid deposition precursors (SO_2, NO_x, and VOC).

Accordingly, the objectives of this study were: 1) to identify and characterize stationary combustion and industrial sources of directly emitted acidic materials in the United States; 2) to evaluate the technical feasibility of control techniques for these sources; and 3) to estimate the costs of applying these control technologies. This assessment was conducted via review and analysis of existing data including the preliminary control strategies evaluated by the Interagency Task Force. The potential for emissions from transportation sources was not examined in this study.

Results of the study can be used to evaluate the merits of controlling directly emitted acidic materials as part of a policy evaluation of overall acid deposition control strategies. For example, if it were determined that for a region local emissions of directly emitted acid materials were more significant than long range precursor emissions, the information in this report could be used to evaluate the cost effectiveness of controlling local sources of directly emitted acidic materials versus sources of long range precursor emissions.

The results of the study are summarized in Section 2. To identify and characterize sources of directly emitted acidic materials, national acidic materials emissions of all combustion and industrial sources were identified by means of a literature search (Section 3 and Appendix A). Model units were then developed for those sources which emit 4,500 Mg (5,000 tons) or more of acidic material per year (Section 4). The model units were used as bases for establishing control techniques and for determining the technical feasibility of candidate conventional control techniques. The cost of control retrofits for the model units were estimated and cost-effectiveness values were determined (Section 5). The cost-effectiveness of acidic materials control was compared with the cost-effectiveness where applicable of SO_2 which is co-emitted with acidic materials. Promising research and development activities relevant to acid materials control were also examined (Section 6).

2.0 RESULTS AND RECOMMENDATIONS

The major combustion and industrial sources of directly emitted acidic materials that were identified during this study are presented in Table 2-1. For most source categories, emissions were estimated using emissions factors and combustion and process capacities found in the literature. Utility and industrial boilers are by far the largest acidic emissions sources in the U.S., producing approximately 760,000 Mg (830,000 tons) and 180,000-250,000 Mg (200,000-275,000 tons) of acidic material emissions per year, respectively. The bases for all emissions data given in Table 2-1 are discussed and referenced in both Section 3 and Appendix A. It was also found that emissions of directly emitted acidic materials represent only 2 percent of the annual emissions of SO_2, NO_x and VOC (which are acid precipitation precursors) from stationary sources.

Based on information obtained in the literature, model plants, including the most applicable acidic material controls, were developed for sources that emit over 4,500 Mg (5,000 tons) of acidic material per year. This cut off point allowed the project funding to be focused on those source categories with the greatest emissions. The major sources considered include utility and industrial boilers, Claus sulfur recovery plants, catalytic cracking units, primary copper smelters, coke oven plants, primary aluminum smelters, and municipal solid waste incinerators. Although Kraft pulp mills, gypsum plants, and cement plants are large sulfate emissions sources, they were not selected for further analysis because the compounds emitted are alkaline or pH neutral. In addition, gypsum ponds were identified as a source category emitting large amounts of HF. However, HF emissions from gypsum ponds are reduced by water treatment methods, whereas this study focused primarily on controls which treat acidic gases. Thus, no further analysis was attempted.

Little performance data is available concerning the control of acidic emissions by currently operating control systems. Therefore, the systems

TABLE 2-1. NATIONAL EMISSIONS ESTIMATES FOR IDENTIFIED SOURCE CATEGORIES

Source Category	Acid Sulfate Emissions 10^3 Mg/yr (10^3 tons/yr)	Nitrate Emissions 10^3 Mg/yr) (10^3 tons/yr)	HCl Emissions (10^3 Mg/yr) (10^3 tons/yr)	HF Emissions (10^3 Mg/yr) (10^3 tons/yr)	Total Emissions (10^3 Mg/yr) (10^3 tons/yr)	Year Data Reported
(1) Utility Boilers						
Coal	107 (117)	64 (70)	496 (546)	60 (66)	756 (831)	1980/1982
Residual Oil	25 (28)					
Distillate Oil	3.6 (4)					
(2) Industrial Boilers						
Coal	20-81 (25-89)	32 (35)	88 (96)	10.6 (11.5)	182-248 (203-273)	1980/1982
Residual Oil	5-10.4 (5.5-11.5)					
Distillate Oil	27 (30)					
(3) Municipal Solid Waste			20 (22)		20 (22)	--
(4) Catalytic Cracking	11.3 (12.5)				11.3 (12.5)	1983
(5) Primary Copper	8.6-10.4 (9.5-11.5)				8.6-10.4 (9.5-11.5)	1984
(6) Primary Aluminum	0.18-0.41 (0.2-0.45)			5.9 (6.5)	6.1-6.3 (6.7-7)	1983
(7) Gypsum Ponds				5.9 (6.5)	5.9 (6.5)	1980
(8) Claus Plants	5.4 (6)				5.4 (6)	1980
(9) Coke Ovens	5 (5.5)				5 (5.5)	1983
(10) Propylene Oxide Manufacturing			2.7-4.1 (3-4.5)		2.7-4.1 (3-4.5)	1980
(11) Residential Boilers			2.7 (3)	0.2 (0.25)	2.9 (3.25)	1974
(12) Sulfuric Acid Plants	1.8 (2)				1.8 (2)	1982
(13) Phosphoric Acid Plants				0.14 (0.15)	0.14 (0.15)	1980
(14) Triple Super Phosphate Manufacturing				0.18 (0.2)	0.18 (0.2)	1980
(15) Primary Zinc	0.2 (0.25)				0.2 (0.25)	1983
(16) Diammonium Phosphate Manufacturing				0.2 (0.25)	0.2 (0.25)	1980
(17) HF Manufacturing				0.01-1.2 (0.01-1.35)	0.01-1.2 (0.01-1.35)	1980

chosen for model unit development are generally those which are demonstrated for control of SO_2 and NO_x and provide the greatest potential for control of acidic material emissions.

Cost analyses were performed to estimate the costs required for retrofitting the selected control systems to model plants. Table 2-2 summarizes the control systems analyzed for each significant source category and their respective cost-effectiveness. Cost-effectiveness is defined as the unit annual cost for removal of the acidic materials. If SO_2 is present in the emission stream, controls were selected for concurrent removal of SO_2 and the acidic materials. Typically, the volume of SO_2 is quite large compared to the volume of acidic materials. Therefore, cost-effectiveness is considerably improved if calculated for the combined removal of acidic materials and SO_2. The combined cost-effectiveness values are included in Table 2-2. The bases for data presented in Table 2-2 are discussed and referenced in Section 5.

The greatest obstacle in this study was the lack of available performance data for acidic emissions control systems. All test data that could be readily obtained is summarized in Table 2-3. No information was available concerning the control of acid nitrates. All test data for removal of acid sulfates are presented in terms of H_2SO_4 mist control and show a wide range of removal efficiencies. Therefore, it would be desirable if research efforts were directed toward quantitating the acid sulfate and acid nitrate control performances of existing applicable gaseous and particulate controls. While data for HCl and HF removal are also lacking, the need for research in this area is not urgent. This is because HCl and HF have high affinities to the alkaline solutions commonly used by FGD systems and, as indicated by the limited test data, removal is expected to be high.

The technologies identified as being most applicable to reducing directly emitted acidic materials are wet/dry scrubbing techniques. Conventional electrostatic precipitators and fabric filters are not as effective because the acidic materials may still be in a gaseous state at the operating conditions where these devices are typically located. As such, it was concluded that the most cost effective control devices for,

TABLE 2-2. SUMMARY OF CONTROLS ANALYZED AND COST-EFFECTIVENESS

Source Category/ Process Capacity	Fuel Type[a]	Control	Acidic Species Controlled	Cost-Effectiveness of Removal: Acidic Material[d] $/Mg ($/ton)		Cost-Effectiveness of Removal: Acidic Material + SO_2 $/Mg ($/ton)	
Industrial Boilers[b]							
30.5 GJ/hr (30 MMBtu/hr)	HSC	Sodium-Based Scrubber	Sulfates, HCl, HF	39,300	(35,700)	810	(740)
	LSC			24,400	(22,200)	2,640	(2,400)
	DO		Sulfates	359,000	(327,000)	4,890	(4,440)
	RO			492,800	(448,000)	1,110	(1,010)
	HSC	Dual Alkali Scrubber	Sulfates, HCl, HF	86,100	(78,300)	1,770	(1,610)
	LSC			66,000	(60,000)	7,130	(6,480)
	DO		Sulfates	999,000	(908,000)	13,600	(12,360)
	RO			1,200,000	(1,090,000)	2,720	(2,470)
	HSC	Lime Spray Dryer	Sulfates, HCl, HF	72,600	(66,000)	1,910	(1,730)
	LSC			59,900	(54,400)	7,930	(7,210)
	DO		Sulfates	626,000	(569,000)	15,400	(14,000)
	RO			704,000	(640,000)	2,920	(2,660)
406 GJ/hr (400 MMBtu/hr)	HSC	Sodium-Based Scrubber	Sulfates, HCl, HF	18,900	(17,200)	390	(350)
	LSC			7,000	(6,300)	750	(680)
	DO		Sulfates	89,000	(81,000)	1,180	(1,070)
	RO			200,000	(182,000)	450	(410)
	HSC	Dual Alkali Scrubber	Sulfates, HCl, HF	20,600	(18,700)	420	(380)
	LSC			11,400	(10,300)	1,220	(1,110)
	DO		Sulfates	156,000	(142,000)	2,060	(1,870)
	RO			249,000	(226,000)	560	(510)
	HSC	Lime Spray Dryer	Sulfates, HCl, HF	21,700	(19,800)	560	(510)
	LSC			14,300	(13,000)	1,810	(1,650)
	DO		Sulfates	119,000	(108,000)	2,870	(2,610)
	RO			172,000	(156,000)	710	(640)
	HSC	Low Excess Air	NO_x[c]	132	(120)	---	
	LSC			9	(8)	---	
	Coal	Overfire Air	NO_x[c]	112	(102)	---	
Utility Boiler[b]							
2,031 GJ/hr (2,000 MMBtu/hr)	HSC	Limestone Wet Scrubber	Sulfates, HCl, HF	64,700	(58,800)	1,130	(1,030)
	LSC			52,600	(47,800)	4,960	(4,510)
	RO		Sulfates	291,000	(264,600)	2,350	(2,140)

TABLE 2-2. SUMMARY OF CONTROLS ANALYZED AND COST-EFFECTIVENESS (Continued)

Source Category/ Process Capacity	Fuel Type[a]	Control	Acidic Species Controlled	Cost-Effectiveness of Removal: Acidic Material[b] $/Mg ($/ton)	Cost-Effectiveness of Removal: Acidic Material + SO_2 $/Mg ($/ton)
	HSC	Wellman-Lord System	Sulfates, HCl, HF	94,600 (86,000)	1,660 (1,510)
	LSC			62,800 (57,100)	5,930 (5,390)
	HSC	Lime Spray Dryer	Sulfates, HCl, HF	62,100 (56,500)	1,140 (1,040)
	LSC			47,300 (43,000)	4,650 (4,230)
	Coal	Low NO_x Burners	NO_x[c]	123 (112)	---
	Coal	Low Excess Air	NO_x[c]	7 (6)	---
	Oil			2 (2)	---
	Coal	Overfire Air	NO_x[c]	96 (87)	---
	Oil			131 (119)	---
5,078 GJ/hr (5,000 MMBtu/hr)	HSC	Limestone Wet Scrubber	Sulfates, HCl, HF	45,700 (41,600)	800 (730)
	LSC			37,600 (34,200)	3,550 (3,230)
	RO		Sulfates	229,000(208,000)	1,850 (1,680)
	HSC	Wellman-Lord System	Sulfates, HCl, HF	74,300 (67,600)	1,300 (1,190)
	LSC			49,400 (44,900)	4,670 (4,240)
	HSC	Lime Spray Dryer	Sulfates, HCl, HF	48,000 (43,600)	880 (800)
	LSC			35,300 (32,000)	3,460 (3,150)
	Coal	Low NO_x Burners	NO_x[c]	71 (64)	---
	Coal	Low Excess Air	NO_x[c]	3 (3)	---
	Oil			1 (1)	---
	Coal	Overfire Air	NO_x[c]	56 (51)	---
	Oil			83 (75)	---
Claus Plants					
10 Mg/day (11 tons/day)		Amine Tail Gas Treatment	Sulfates	242,800(220,300)	2,420 (2,200)
100 Mg/day (110 tons/day)				77,200 (70,000)	770 (700)
250 Mg/day (275 tons/day)				54,900 (49,800)	550 (500)

TABLE 2-2. SUMMARY OF CONTROLS ANALYZED AND COST-EFFECTIVENESS (Continued)

Source Category/ Process Capacity	Fuel Type[a]	Control	Acidic Species Controlled	Cost-Effectiveness of Removal: Acidic Material[h] $/Mg ($/ton)	Cost-Effectiveness of Removal: Acidic Material + SO_2 $/Mg ($/ton)
Fluid Catalytic Cracking Units					
2,500 m^3/sd (15,725 bbl/sd)[i]	ISF[d]	Sodium-Based Scrubber[e]	Sulfates	93,640 (84,950)	1,090 (990)
	HSF[d]			63,450 (57,560)	740 (670)
8,000 m^3/sd (50,320 bbl/sd)[i]	ISF[d]			62,580 (56,770)	730 (660)
	HSF[d]			47,830 (43,390)	560 (510)
Primary Copper Smelters					
115,000 Mg/yr (127,000 tons/yr)		Sulfuric Acid Plant[f]	Sulfates	9,800 (8,900)	130 (120)
Coke Oven Plants					
2000 Mg/day (2200 tons/day)		Vacuum Carbonate System	Sulfates	11,700 (10,600)	950 (870)
6000 Mg/day (6600 tons/day)				6,900 (6,300)	570 (520)
Municipal Solid Waste (MSW)					
380 Mg/day (420 tons/day)	MSW	Sodium-Based Scrubber[g]	HCl	1,900 (1,730)	1,020 (1,120)
730 Mg/day (800 tons/day)	MSW			1,480 (1,340)	970 (880)

[a] HSC = high-sulfur coal; LSC = low-sulfur coal; DO = distillate oil; RO = residual oil.

[b] Boiler capacities presented in terms of heat input.

[c] No emissions data, specifically in terms of acid nitrate emissions, were available. Thus, all cost effectiveness results are given in terms of controlling NO_x emissions.

[d] Catalytic cracking unit feed rather than fuel. ISF = intermediate-sulfur feed (1.5 wt. % S); HSF = high-sulfur feed (3.5 wt. % S).

[e] High energy venturi scrubber using soda ash-based scrubbing liquor.

[f] Single stage acid plant.

[g] Employs caustic soda-based scrubbing liquor.

[h] Excludes benefits of concurrent SO_2 reductions.

[i] m^3/sd: cubic meter per stream day
bbl/sd: barrel per stream day.

TABLE 2-3. PERFORMANCE DATA FOR ACIDIC MATERIALS CONTROL[a]

Acidic Material	Concentration (ppmv) Inlet	Outlet	Percent Removal	Source
H_2SO_4[b]	20 - 30	4 - 10	33 - 80	Reference 1
H_2SO_4[c]	2.6	1	61	Reference 1
H_2SO_4[c]	3 - 9	1 - 5	44 - 67	Reference 1
H_2SO_4[c]	4 - 19	1 - 8	39 - 78	Reference 2
HCl[c]	---	---	94 - 100	Reference 2
HF[c]	---	---	93 - 99	Reference 2

[a] All data apply to utility wet FGD systems. Presented as ranges of test data for particular systems.

[b] FGD employed on oil-fired boiler.

[c] FGD employed on coal-fired boiler.

sulfates, fluorides and chlorides are the same controls that would be employed for SO_2. Conventional combustion modification techniques, used to control NO_x emissions from boilers, were identified as the best commercially available methods for reducing nitrate emissions.

2.1 REFERENCES

1. Telecon. Balfour, D. W., Radian Corporation, Austin, Texas with Waddell, J. T., Radian Corporation, Research Triangle Park, North Carolina. 27 August 1985.

2. Smith. E. O., et al. (Black & Veatch Consulting Engineers), Full-Scale Characterization of Conesville Unit 5, prepared for Electric Power Research Institute, Palo Alto, California, EPRI CS-2525, August 1982.

3.0 SUMMARY OF ACIDIC EMISSIONS ESTIMATES

Identification and characterization of acidic material emissions from industrial and combustion sources in the U.S. were accomplished through a literature search. The specific compounds examined include sulfates, HCl, HF, and nitrates. Sulfate emissions were further examined to identify acidic content. Acid sulfate emissions, for the purpose of this study, can be defined as that portion of total sulfate emissions which would readily become acid deposition. If determined by the controlled condensation system (CCS) test method, for example, this would include free H_2SO_4 and SO_3. Similarly, acid nitrate emissions can be defined as that portion of total nitrate emissions which would readily become acid deposition, (e.g., HNO_3).

Table 3-1 presents the acidic emissions estimates for each source category identified, as well as the information sources used. A more detailed discussion of how the estimates were derived can be found in Appendix A.

Table 3-1 identifies the sources of emissions data. Work Group 3B (WG3B) emissions estimates and the NAPAP emissions inventory were used if possible. Otherwise, most emission factors came from EPA sources. Total emissions were derived by multiplying the emissions factors by industry capacities taken from EPA, DOE, Bureau of Mines or industry sources. An emission factor for nitrates from coal-fired utility boilers was reported in one reference and was assumed to apply for coal-fired industrial boilers also. Emission data for NO_x was available for several industrial processes (HNO_3, adipic acid, organic nitrogen, nitrocellulose) but nitrate emissions data was not available.

The national total of acidic material emissions from stationary sources is approximately 1.0 to 1.1 million Mg (1.1 to 1.2 million tons) per year. This equals about 2 percent of the annual national emissions of the acid precipitator precursors, SO_2, NO_x, and volatile organic compounds (VOC) from sources other than transportation. In the U. S.-Canadian Memorandum of

TABLE 3-1. SUMMARY OF NATIONAL ACIDIC EMISSIONS ESTIMATES

Source Category	Acidic Species Emitted	Emissions Estimate thousand Mg/yr (thousand tons/yr)	Derivation of Estimate^{a,b}
Utility Boilers			
Coal-fired	acid sulfate	107 (117)	Emission factors derived from References 2, 5, 6 and WG-3B (Reference 1) multiplied by combustion capacity reported in Reference 7.
	HCl	496 (546)	Emission factor given in Reference 33 multiplied by combustion capacity reported in Reference 7.
	HF	60 (66)	Emission factor reported in Reference 33 multiplied by combustion capacity reported in Reference 7.
	nitrate	64 (70)	Emission estimate presented in Reference 44.
Residual oil-fired	acid sulfate	25 (28)	Emission factor given in Reference 2, emission factor derived from emissions data (Reference 2), and combustion capacity reported in Reference 8.
Distillate oil-fired	acid sulfate	3.6 (4)	Emission factor derived from Reference 2 and WG-3B (Reference 1) and combustion capacity reported in Reference 8.
Industrial Boilers			
Coal-fired	acid sulfate	20-81 (25-89)	Emission factor presented in Reference 2 and emission factor derived from emissions data (Reference 2) multiplied by combustion capacity presented in Reference 7.
	HCl	88 (96)	Emission factor presented in Reference 33 multiplied by combustion capacity reported in Reference 7.
	HF	10.4 (11.5)	Emission factor given in Reference 33 multiplied by combustion capacity presented in Reference 7.
	nitrate	32 (35)	Emissions estimate presented in Reference 44.

TABLE 3-1. SUMMARY OF NATIONAL ACIDIC EMISSIONS ESTIMATES (Continued)

Source Category	Acidic Species Emitted	Emissions Estimate thousand Mg/yr (thousand tons/yr)	Derivation of Estimate[a,b]
Residual oil-fired	acid sulfate	5-10.4 (5.5-11.5)	Emission factor presented in Reference 2 and emission factor derived from emissions data (Reference 2) multiplied by combustion capacity reported in Reference 8.
Distillate oil-fired	acid sulfate	27 (30)	Emission factor derived from Reference 2 and WG3B (Reference 1) multiplied by combustion capacity reported in Reference 8.
Municipal Solid Waste	HCl	20 (22)	Emission factor given in Reference 33 multiplied by combustion capacity reported in Reference 38.
Catalytic Cracking	acid sulfate	11.3 (12.5)	WG3B (Reference 1) emission factor multiplied by process capacity reported in Reference 19.
Primary Copper	acid sulfate	8.6-10.4 (9.5-11.5)	Emission factor presented in Reference 24 and emission factor derived from WG3B (Reference 1) estimates multiplied by process capacity reported in Reference 23.
Primary Aluminum	acid sulfate	0.18-0.41 (0.2-0.45)	Emission factors derived from WG3B (Reference 1) and Reference 4 multiplied by process capacity reported in Reference 20.
	HF	5.9 (6.5)	Emission factors presented in Reference 33 multiplied by process capacity reported in Reference 43.
Gypsum Ponds	acid sulfate	5.9 (6.5)	Emission factor given in Reference 40 multiplied by process capacity presented in Reference 41.
Claus Plants	acid sulfate	5.4 (6)	Emission factor given in Reference 2 multiplied by process capacity reported in Reference 29.
Coke Ovens	acid sulfate	5 (5.5)	Emission factor given in Reference 2 multiplied by process capacity reported in Reference 9.
Propylene Oxide Manufacturing	HCl	2.7-4.1 (3-4.5)	Emission factor derived from Reference 36 multiplied by process capacity presented in Reference 37.

TABLE 3-1. SUMMARY OF NATIONAL ACIDIC EMISSIONS ESTIMATES (Continued)

Source Category	Acidic Species Emitted	Emissions Estimate thousand Mg/yr (thousand tons/yr)	Derivation of Estimate[a,b]
Sulfuric Acid Plants	acid sulfate	1.8 (2)	WG3B (Reference 1) emission factor multiplied by process capacity reported in Reference 12.
Phosphoric Acid Plants	HF	0.14 (0.15)	Emission factor given in Reference 40 multiplied by process capacity reported in Reference 41. Level of control of existing plants unavailable; range represents assumptions of 50-100 percent of plant capacity controlled.
Primary Zinc	acid sulfate	0.2 (0.25)	Emission factor given in Reference 2 multiplied by process capacity reported in Reference 25 and estimates of existing control (Reference 2, Reference 26).
Triple Super Phosphate Manufacturing	HF	0.18 (0.2)	Emission factor given in Reference 42 multiplied by process capacity given in Reference 41.
Diammonium Phosphate Manufacturing	HF	0.2 (0.25)	Emission factor presented in Reference 42 multiplied by assumed process capacities (based on information presented in Reference 41).
HF Manufacturing	HF	0.01-1.2 (0.01-1.35)	Emission factors given in Reference 33 multiplied by process capacity reported in Reference 33. Level of control on existing plants unavailable; range represents assumptions of 50-100 percent of plant capacity controlled.

[a] All references are presented at the end of Appendix A.

[b] WG3B - Working Group 3B (Reference 1).

Intent on Transboundary Air Pollution, Working Group 3B reported that the national emissions of SO_2, NO_x, and VOC in 1980 were 23.3, 10.8, and 16.9 million Mg (25.6, 11.9, and 18.6 million tons), respectively, for sources other than transportation. This totals 51.0 million Mg (56.1 million tons) of acid precipitation precursors as compared to 1.0 to 1.1 million Mg (1.1 to 1.2 million tons) of directly emitted acidic materials.

4.0 DEVELOPMENT OF MODEL UNITS

Model units were developed for the combustion and industrial source categories with estimated acidic material emissions greater than 10 million pounds per year. A literature search was done to identify representative sizes, process components, operational parameters, and demonstrated emissions control equipment for each source category selected. The model units are based on this information.

Sources chosen include industrial and utility boilers, Claus plants, fluid catalytic cracking units, primary copper smelters, coke ovens, primary aluminum smelters, and municipal solid waste incinerators. These categories are discussed in Sections 4.1 through 4.7.

4.1 INDUSTRIAL AND UTILITY BOILERS

4.1.1 Model Boilers

Utility and industrial boilers are the largest emitters of sulfates, nitrates, chlorides, and fluorides. An extensive amount of boiler control technology cost data have been developed by EPA under standards development and research programs. Costing models for commercial and developmental technologies are available for a wide range of sizes and types. For this study the model plant sizes and types selected are consistent with those used in the development of the utility and industrial boiler New Source Performance Standards. Therefore, the cost data for control technology for this program is well documented.

Table 4.1-1 shows the characteristics of the model plants used for industrial and utility boilers. These characteristics cover most of the differences in boilers found at various sites. The principal boiler fuels are coal, residual oil, distillate oil and natural gas. Significant amounts of acidic emissions are not produced by natural gas-fired boilers; therefore, model boilers were chosen to represent the other three commonly used fuels. Since coal properties such as sulfur and ash content can vary

TABLE 4.1-1. MODEL UNITS FOR INDUSTRIAL AND UTILITY BOILERS

Fuel	Heat Input Capacity GJ/hr (10^6 Btu/hr)	Boiler Configuration
High-Sulfur Coal	30.5 (30)	Package, watertube, underfeed stoker
Low-Sulfur Coal	30.5 (30)	Package, watertube, underfeed stoker
Distillate Oil	30.5 (30)	Package, firetube
Residual Oil	30.5 (30)	Package, firetube
High-Sulfur Coal	406 (400)	Field erected, watertube, PC
Low-Sulfur Coal	406 (400)	Field erected, watertube, PC
Distillate Oil	406 (400)	Field erected, watertube
Residual Oil	406 (400)	Field erected, watertube
High-Sulfur Coal	2,031 (2,000)	Field erected, watertube, PC
Low-Sulfur Coal	2,031 (2,000)	Field erected, watertube, PC
Residual Oil	2,031 (2,000)	Field erected, watertube
High-Sulfur Coal	5,078 (5,000)	Field erected, watertube, PC
Low-Sulfur Coal	5,078 (5,000)	Field erected, watertube, PC
Residual Oil	5,078 (5,000)	Field erected, watertube

considerably, model boilers were selected for both low sulfur coal (LSC) and high sulfur coal (HSC) applications. Representative boiler design capacities within each fuel type were then selected to cover the range of expected capacities for the utility and industrial boiler populations.

Four size categories were chosen for model boilers. These were 30.5, 406, 2,031, and 5,078 GJ/hr (30, 400, 2,000 and 5,000 million Btu/hr) of thermal input. Capacities of industrial boilers range from less than 1.52 GJ/hr (1.5 million Btu/hr) to greater than 508 GJ/hr (500 million Btu/hr).[1] The majority of boilers at the lower end of the capacity range are used for space heating whereas the boilers at the upper end of the capacity range are generally used for process steam and, in some cases, electric power generation. The 30.5 and 406 GJ/hr (30 and 400 million Btu/hr) size ranges were chosen as representative of small and large industrial boilers. Utility boilers tend to be much larger than industrial boilers and can have thermal inputs as large as 15,230 GJ/hr (15 billion Btu/hr). The 2,031 and 5,078 GJ/hr (2,000 and 5,000 million Btu/hr) categories were chosen as representative of utility boilers.

In addition to fuel type and capacity, boilers also vary according to heat transfer configuration. The three basic heat transfer configurations are cast iron, firetube, and watertube. Cast iron boilers are usually small and so contribute very little to national emissions. Therefore, a model plant representing cast iron boilers was not included.

In firetube boilers, the products of combustion flow through tubes that are surrounded by water. These units range in size from 3.05 to 20.3 GJ/hr (3.0 to 20 x 10^6 Btu/hr) thermal input and are used primarily for heating systems, to produce industrial process steam, and as portable power boilers.[2] Firetube boilers are generally used where steam/hot water demand can be maintained relatively constant because they are susceptible to structural failure when subjected to large variations in steam demand.[2] Over 90 percent of the installed capacity of firetube boilers is oil- or gas-fired.[3]

A watertube boiler is one in which the hot combustion gases contact the outside of the heat transfer tubes, while the boiling water and steam are contained within the tubes. Usually, the tubes are connected to an overhead drum with sufficient space provided for separation of the steam from the boiler water.

Watertube boilers can generate high-pressure, high-temperature steam, up to 12,000 kPa (1740 psi) and 530^{0}C (1000^{0}F), and are available in many sizes. The tubes are of relatively small diameter, 5 cm (2.0 inch), providing rapid heat transfer, good response to steam demands, and high efficiency.[2]

There are two main types of coal-fired watertube boilers: pulverized coal and stoker-fired. In pulverized coal-fired boilers the fuel is pulverized to the consistency of light powder and pneumatically injected through the burners into the furnace. Combustion begins at the burners and continues into the furnace. A stoker is a conveying system that serves both to feed the coal into the furnace and to provide a grate upon which the coal is burned. Since feed rates by stoker units are limited, stokers are generally used on units rated at less than 406 GJ/hr (400 x 10^6 Btu/hr) heat input.[3] Therefore, only model boilers in the smallest size category (30.5 GJ/hr) were the only boilers considered for stoker firing. Boilers in the other two size categories were represented by pulverized coal model boilers.

Only small boilers can be assembled at the factory and then shipped to the site. Larger boilers must be field erected. For this reason the model boilers representing boilers in the 30.5 GJ/hr (30 million Btu/hr) category were packaged, while the remaining model boilers were assumed to be field erected.

4.1.2 Control Of Acidic Emissions From Boilers

A variety of demonstrated devices for controlling emissions of SO_2, NO_x, and particulate matter (PM) from industrial and utility boilers are commercially available. Methods of controlling acidic material emissions, however, are not as well defined or established. For the purpose of developing model units, demonstrated SO_2, NO_x, and PM controls were selected which provide the highest level of concurrent acidic materials control. Flue gas desulfurization (FGD) systems for SO_2 control were chosen for control of sulfates, HCl, and HF. Combustion modification techniques used for NO_x control were selected for nitrate control.

4.1.2.1 Sulfates, HCl, and HF. Flue gas desulfurization (FGD) systems use processes which contact flue gas with an alkaline "scrubbing" liquor to absorb SO_x and acid gases (HCl and HF). These systems are typically classified as "wet" or "dry" depending on the physical state in which the absorption products leave the scrubbing unit. FGD processes can also be described as regenerable or non-regenerable. Regenerable systems recover the sulfur compounds removed from the flue gas as a salable by-product such as sulfuric acid, liquid SO_2, or elemental sulfur. Non-regenerable systems yield solid or sludge wastes which require environmentally sound disposal methods.

While wet FGD systems achieve SO_2 removal efficiencies on the order of 90 percent, they are not as efficient in removing acid sulfates. Reference 4 estimates a sulfate removal efficiency of 35 percent. Although wet FGD systems do not optimize acid sulfate control, they usually achieve good overall acid gas removal. In fact, HCl and HF are removed with at least the same efficiency as SO_2.[5,6]

For industrial boilers, the most prevalent wet FGD system is the sodium-based scrubber. Sodium scrubbers employ a sodium based solution as the scrubbing medium. These systems comprise about 98 percent of all industrial wet FGD installations.[7] Most sodium-based scrubbers currently in use on industrial boilers are employed on oil field steam generators. However, even after eliminating applications such as oil field steam generators, paper mills, soda ash, and textile plants, sodium-based scrubbers represented at least 70 percent of the total wet FGD systems operating in 1984.[7] The second most prevalent industrial wet FGD technology is the dual alkali process. Dual alkali scrubbers comprise about 1 percent of the industrial wet FGD population.[7] This process also involves the absorption of SO_2 (and acidic materials) in a sodium based solution. However, the absorbent is regenerated via reaction with a calcium based slurry to produce a sludge waste that must be disposed of.

The most common wet FGD systems employed on utility boilers are lime/limestone wet scrubbers. These devices use a calcium carbonate solution to scrub flue gases. By September 1980, limestone wet scrubbers comprised 46.1 percent of all FGD systems on utility boilers with lime wet scrubbers following at 39.5 percent.[8] The predominant regenerable FGD process, commercially proven for utility boiler applications, is the Wellman-Lord Sulfite Scrubbing Process. Wellman-Lord systems account for about 4 percent of the total U.S. operating and planned utility FGD capacity.[9]

The most prevalent dry FGD system for industrial and utility boilers is the spray dryer. Spray drying involves contacting the flue gas with an atomized lime slurry or sodium carbonate solution. The hot flue gas dries the droplets to form a dry waste product, while the absorbent reacts with SO_2 and acidic materials. The dry waste product, unreacted absorbent, and boiler fly ash can then be collected in a baghouse or an electrostatic precipitator.

Acid sulfate removal efficiencies should be higher for spray dryers which use a baghouse for collection of solids than for wet FGD systems. This is because the potential for H_2SO_4 mist is minimized, and the acid sulfates have additional time to react with absorbent captured on the fabric filter. Combining the Reference 4 estimates for sulfate removal in FGD systems and fabric filters yields a 65 percent removal efficiency. While this estimate may be overly optimistic, it should clearly be higher than for wet systems.

HCl and HF removal efficiencies for spray drying systems are about 90 percent. These are equivalent to the efficiencies achieved by wet systems.

4.1.2.2 Nitrates. Nitrogen oxides (NO_x) are formed during the combustion process by two mechanisms. One involves the thermal fixation of oxygen and nitrogen present in the combustion air. The predominant mechanism is the reaction of oxygen in the combustion air with nitrogen in the fuel. No data could be found specifically for the control of nitrates. Thus, for the purpose of this study, it is assumed that reduction of NO_x emissions will proportionally decrease the potential for nitrate formation. As a result, NO_x controls are chosen for analysis.

Control of NO_x emissions is generally accomplished by modifying the combustion process. One method is the low excess air (LEA) operation. This simply reduces the primary combustion air flow to decrease the local flame zone concentration of oxygen. NO_x emissions can be reduced by about

15 percent in this manner.[10,11] Off-stoichiometric, or staged, combustion is another modification technique. In this process, overfire air (OFA) ports can be used to decrease oxygen availability in the primary flame zone while providing sufficient air downstream for complete combustion. OFA can reduce NO_x emissions by about 30 percent.[11] A technique yielding higher NO_x reductions is the low-NO_x burner. These burners are specifically designed to minimize flame turbulence, delay mixing of fuel and air, and create oxygen deficient zones in the initial combustion area. Reduction efficiency for low-NO_x burners is about 50 percent.[11]

4.1.3 Model Control Systems

Table 4.1-2 presents the acidic material control systems chosen for analysis with model boilers. Limestone wet scrubbers were the only FGD systems selected for oil-fired utility boilers. This is because no cost data were found for other systems applied on oil-fired boilers of comparable size. NO_x controls were not chosen for boilers under 406 GJ/hr (400×10^6 Btu/hr) capacity. Uncontrolled emission factors from Reference 10 indicate that the 30.5 GJ/hr (30×10^6 Btu/hr), packaged boilers would meet the current new source performance standard (NSPS) for NO_x emissions without additional control.

4.2 CLAUS PLANTS

Claus sulfur recovery plants in the U.S. produce an estimated 5,400 Mg (12,000 tons) of acid sulfate per year. In addition to a significant national production, two individual plants were indicated to produce large amounts of local acid sulfate emissions. Each of these two plants produced in excess of 550 tons of acid sulfate per year. Also, a large number of smaller plants are located in Texas, Mississippi, and Wyoming which may cause local problems.

Five types of control systems are presently being used in the U.S. to control emissions from Claus plants. These are ARCO, Beavon, IFP-1, SCOT, and Wellman-Lord Systems. Table 4.2-1 shows the extent to which each type of system is used. The IFP-1 process is merely an extension of the Claus

TABLE 4.1-2. MODEL CONTROL SYSTEMS FOR BOILERS

Boiler Heat Input Capacity GJ/hr (MMBtu/hr)	Fuel[a]	Sulfate, HCl, HF Control	NO_x Control
30.5 (30)[b]	HSC, LSC, DO, RO	Sodium-based scrubber Dual alkali scrubber Lime spray dryer	Low excess air Overfire air
406 (400)[b]	HSC, LSC, DO, RO	Sodium-based scrubber Dual alkali scrubber Lime spray dryer	Low excess air Overfire air
2,031 (2,000)[c]	HSC, LSC	Limestone wet scrubber Wellman-Lord systems Lime spray dryer	Low excess air Overfire air Low-NO_x burners
	RO	Limestone wet scrubber	Low excess air Overfire air
5,078 (5,000)[c]	HSC, LSC	Limestone wet scrubber Wellman-Lord systems Lime spray dryer	Low excess air Overfire air Low-NO_x burners
	RO	Limestone wet scrubber	Low excess air Overfire air

[a] HSC = high-sulfur coal, LSC = low-sulfur coal, DO = distillate oil, RO = residual oil.

[b] Industrial boiler

[c] Utility boiler

TABLE 4.2-1. CLAUS PLANT TAIL GAS CONTROL PROCESSES CONSTRUCTED BEFORE 1983[4]

Process	Type of Process	Number of Units	Percent of Total
IFP-1	Extended Claus	6	8
Wellman-Lord	Oxidation/Absorber	5	7
ARCO	Reduction/Absorber	4	5
Beavon	Reduction/Absorber	30	39
SCOT	Reduction/Absorber	31	41

process. The other four processes are tail gas scrubbing systems. The Wellman-Lord system uses an oxidation reaction, while the other three scrubbers use a reduction reaction. All three of these reduction processes reduce all sulfur species in the tail gas to H_2S. They differ in the steps taken to convert the H_2S to elemental sulfur. IFP-1 processes represent roughly 99.0 percent control while tail gas scrubbers can achieve up to 99.9 percent control.

Reference 12 gave the total production from Claus plants in the U.S that were using some form of tail gas control in 1980. This total production was 3.2 million Mg (3.5 million tons). Total production from all Claus plants in that year was 3.9 million Mg (4.3 million tons). Therefore, 81 percent of all Claus plant production in 1980 used tail gas controls.

Assuming that uncontrolled plants collect 96 percent of the sulfur and controlled plants collect 99.9 percent of the sulfur, uncontrolled plants would emit 40 times more acid sulfate than a controlled plant of the same size. Using this factor with the percentages of plants controlled and uncontrolled gives a factor for the percentage of emissions coming from uncontrolled plants. This percentage is 90 percent. Therefore, 4,900 Mg (5,400 tons) of acid sulfate were produced by uncontrolled plants in 1980. If controlled, emissions reduction from these plants would be 4,800 Mg (5,250 tons).

It is important to note that all Claus plants on which construction or modification began after October 4, 1976 and have capacities greater than 20 Mg/day (22 tons/day) are subject to a New Source Performance Standard (NSPS) limiting SO_2 emissions. Since 1980, a large number of Claus plants have begun operation (e.g., 816,000 Mg [900,000 tons] production capacity in 1981 and 1982). Practically all new units are large enough to fall under the NSPS and employ tail gas controls. Assuming a plant life of 15 years,[15] all plants constructed prior to NSPS control will have to be replaced before 1995. Nevertheless, the high degree of control that can be achieved before then has prompted the development of model plants for this study.

Table 4.2-2 gives the model Claus plants that will be used. Of the 17 Claus plants that became operational in 1981 and 1982, 7 were less than 100 Mg/D (110 TPD), 5 were between 100 and 199 Mg/D (110 and 219 TPD),

TABLE 4.2-2. CLAUS PROCESS MODEL PLANTS*

	Sulfur Intake Mg/D (TPD)	Efficiency (%)	Number of Catalytic Stages	Heat Recovery
1	10 (11)	95.10	1	No
2	100 (110)	96.64	2	No
3	250 (276)	96.64	2	Yes

*All model plants assume one Claus furnace and 350 days/year operation.

4 were between 200 and 299 Mg/D (221 and 330 TPD), and only 1 was above 300 Mg/D (331 TPD). All plants had either one or two catalytic stages.

As was shown in Table 4.2-1, 85 percent of all tail gas control systems constructed before 1983 were reduction processes. As shown in Table 4.2-3, 95 percent of those processes beginning operation in 1981 and 1982 were reduction processes. Since the reduction processes appear to be the predominant choice for Claus plant control, only these systems will be considered in the cost estimating. All three types of reduction processes have similar costs. Therefore, only the Scot process will be used in cost calculations.

4.3 FLUID CATALYTIC CRACKING

In Table 3-1, it was indicated that catalytic cracking units in the U.S. emit approximately 11,000 Mg (12,500 tons) of acid sulfate per year. Ninety-seven percent of these units are fluid catalytic cracking (FCC) units,[13] representing about 9,300 Mg (10,200 tons) of acid sulfate emissions per year. Since FCC units dominate the catalytic cracking population and are phasing out other methods of catalytic cracking,[14] FCC will be the only technology of this type considered for model plant development. High local emissions of sulfates are reported for areas of Texas and Louisiana where petroleum refineries are concentrated. It is assumed that there are also high local emissions from FCC units located in these states (Appendix A).

Acid sulfates are produced in an FCC unit during the catalyst regeneration step, where coke deposits are burned off the catalyst surface. For this reason, emission control devices are applied to FCC regenerators. The only type of control device which has been demonstrated on FCC regenerators is the wet sodium-based scrubber. Sodium-based scrubbers are flue gas desulfurization (FGD) devices that employ a sodium-based liquor to absorb sulfur dioxide from the flue gas. These scrubbers have been applied to seven FCC units at five refineries, representing 11 percent of the U.S. fresh feed capacity.[14]

By January 1979, 31 refineries employed hydrotreating to part or all of their feed stocks, representing about 18 percent of U.S. fresh feed capacity.[14] Hydrotreating involves heating the feed stream in the presence

TABLE 4.2-3. TAIL GAS CONTROL PROCESSES CONSTRUCTED IN 1981 AND 1982[4]

Process	Type of Process	Number of Units	Percent of Total
IFP-1	Extended Claus	0	0
Wellman-Lord	Oxidation/Absorber	1	5
ARCO	Reduction/Absorber	1	5
Beavon	Reduction/Absorber	7	37
SCOT	Reduction/Absorber	10	53

TABLE 4.3-1. SULFATE EMISSIONS DATA FOR FCC UNIT REGENERATORS

Control Type	U.S. Fresh[1] Feed Capacity Treated m^3/sd (bbl/sd)	Percent of U.S. Fresh Feed Capacity Treated	Current Sulfate Emissions Mg/yr (tons/yr)	Sulfate Emissions with 35 Percent Control Mg/yr (tons/yr)
Sodium scrubbing	87,800 (552,000)	11	785 (865)[a]	785 (865)
Hydrotreating	145,000 (912,000)	18	599 (660)[b]	599 (660)[c]
None	573,000 (3,605,000)	71	7,892 (8,700)	5,126 (5,650)
TOTAL	805,800 (5,069,000)	100	9,276 (10,225)	6,510 (7,125)

[a] Based on an average acid sulfate removal efficiency of 35 percent. Reference 4.

[b] Assumes that acid sulfate removal efficiency is equal to SO_2 removal efficiency at 70 percent.

[c] Added control unnecessary if acid sulfate removal by hydrotreating is greater than 35 percent.

of hydrogen gas to reduce sulfur content. However, this process is site specific and is applied for economic and process reasons rather than to comply with limits on sulfur oxides emissions. Hydrotreating gives an estimated 70 percent SO_2 reduction efficiency.[14]

Table 4.3-1 presents the amounts of annual acid sulfate emissions for both controlled and uncontrolled FCC units. These were calculated using the WG3B emissions factor (43 kg/m^3 [15 lbs sulfate/1000 bbl] fresh feed capacity) presented in Section 3.1.7. Uncontrolled FCC regenerators emit approximately 7,900 Mg (8,700 tons) of acid sulfate per year, accounting for 85 percent of total annual acid sulfate emissions.

Reference 4 estimates a sulfate removal efficiency of 35 percent by wet FGD systems. Applying this level of control to uncontrolled FCC units would reduce national sulfate emissions by 30 percent, to a level of about 6,400 Mg (7,000 tons) per year. The amount of sulfate emission reductions realized by hydrotreating is not clear from available data. For the purpose of this study, it is assumed that a reduction of at least 35 percent is achieved and additional control is unnecessary.

Since the majority of FCC units are uncontrolled and a significant reduction in acid sulfates emissions could be achieved, model plants were developed for further analysis. These plants are presented in Table 4.3-2. The two fresh feed capacities selected are representative of FCC units constructed since 1975.[14] The two values of feed sulfur content reflect intermediate and high feed sulfur levels normally seen by FCC units.[14]

A New Source Performance Standard (NSPS) was proposed in January 1984, limiting sulfur oxides emissions from FCC unit regenerators. Under this standard, add-on control devices (such as sodium scrubbers) must control 90 percent of SO_x emissions from units using feed streams with sulfur contents greater than 0.3 percent.[15] Cost analysis will be performed for retrofitting sodium-based scrubbers on model units to meet this NSPS. A sulfate removal efficiency of 35 percent will be assumed.

4.4 PRIMARY COPPER

Acid sulfate emissions from primary copper smelters in the U.S. are estimated to be 9,000 to 10,000 Mg (9,500 to 11,500 tons) per year (Table 3-1). Emission rates vary from plant to plant, depending on smelter

TABLE 4.3-2. MODEL PLANTS FOR FLUID CATALYTIC CRACKING UNITS[a]

Fresh Feed Capacity m^3/sd (bbl/sd)	Feed Sulfur Content (wt. %)	Sulfate Control Efficiency %
2500 (15,725)	1.5	35
	3.5	35
8000 (50,320)	1.5	35
	3.5	35

[a] Based on a proposed New Source Performance Standard of 90 percent SO_x control for add-on devices with 0.3 percent sulfur feed cut-off (Reference 15).

size, type of process equipment, and the presence or absence of SO_2 control. Table 4.4-1 presents a list of domestic smelters currently operating and their basic equipment inventories.

The only type of control system that has been demonstrated for U.S. copper smelters is the sulfuric acid plant. Acid plants produce sulfuric acid by catalytically oxidizing SO_2, which is captured from smelter off-gases, to SO_3. Two types of acid plants are currently available and in use. One is the single contact, single absorption (SCSA) plant which utilizes one absorption unit. An improved version, available since about 1972, is the double contact, double absorption (DCDA) plant which employs two absorbers. SCSA units achieve about 96 percent SO_2 control while DCDA units achieve 99.7 percent control.[16] Eight of the ten operating domestic copper smelters use acid plants to control part or all of their off-gases. Two smelters remain uncontrolled. A Dimethylaniline (DMA) scrubbing system is used by the Tennessee Chemical Company smelter in Copperhill, Tennessee to supplement their acid plants.[17] However, this smelter is the smallest in the United States and serves primarily as a sulfuric acid producer. Thus, DMA scrubbers will not be considered further.

Primary SO_2 emissions from any roaster, smelting furnace, or converter at new copper smelters and modified existing smelters are limited by a new source performance standard (NSPS) to 650 ppm.[17] However, existing reverberatory furnaces which process high impurity charges are exempt from the NSPS. Sulfur dioxide emissions from reverberatory furnaces may increase because of modifications as long as total emissions from the smelter do not increase. This is because reverberatory furnaces produce "weak" SO_2 off-gas streams, and no cost-effective control method has been found. As a result, smelters that employ reverberatory furnaces treat only roaster and converter off-gases. The two uncontrolled domestic copper smelters use reverberatory furnaces but do not control any portion of roaster or converter off-gases. Although the Copper Range smelter at White Pine, Michigan, is uncontrolled, it processes a non-sulfide copper ore;[18] thus, sulfate emissions are low. Emissions of SO_2 at the remaining uncontrolled smelter (Phelps Dodge, Douglas, Arizona) are estimated by WG3B to be about 258,000 Mg/yr (284,000 tons/year).[16] This results in approximately 3,500 Mg (3,850 tons)

TABLE 4.4-1. DOMESTIC PRIMARY COPPER SMELTERS[16,17]

Company	Location	Capacity Mg/yr (tons/yr)	Process Equipment	SO_2 Control Equipment
ASARCO	El Paso, Texas	90,700 (100,000)	4 Multihearth Roasters 1 Reverberatory Furnace 3 Converters	Acid Plants (Dual Stage)
	Hayden, Arizona	181,000 (200,000)	12 Multihearth Roaster 2 Reverberatory Furnaces 5 Converters	Acid Plants
Tennessee Chemical Company	Copperhill, Tennessee	13,600 (15,000)	1 Fluid Bed Roaster 1 Electric Furnace 1 Converter	Acid Plants (Dual Stage) DMA[a]
Inspiration Consolidated Copper Company	Miami, Arizona	136,000 (150,000)	1 Rotary Dryer 1 Electric Furnace 5 Converters	Acid Plants (Dual Stage)
Magma Copper Company	San Manuel, Arizona	181,500 (200,000)	3 Reverberatory Furnaces 5 Converters	Acid Plants
Kennecott Copper Corporation	Hayden, Arizona	70,800 (78,000)	1 Fluid Bed Roaster 1 Reverberatory Furnace 3 Converters	Acid Plants
	Hurley, New Mexico	72,500 (80,000)	1 Rotary Dryer 1 Reverberatory Furnace 4 Converters	Acid Plants

TABLE 4.4-1. DOMESTIC PRIMARY COPPER SMELTERS[16,17] (Continued)

Company	Location	Capacity Mg/yr (tons/yr)	Process Equipment	SO_2 Control Equipment
Copper Range Company	White Pine, Michigan	51,700 (57,000)	1 Rotary Dryer 2 Reverberatory Furnaces 2 Converters	None
Phelps Dodge Corporation	Douglas, Arizona	115,200 (127,000)	24 Multihearth Roasters 3 Reverberatory Furnaces 5 Converters	None
	Hidalgo, New Mexico	162,500 (179,000)	1 Rotary Dryer 1 Slag Furnace 3 Converters	Acid Plants (Dual Stage)

[a] DMA = Dimethylaniline Scrubbing System

of acid sulfate emissions per year. If this smelter was controlled by acid plants, acid sulfate emissions from copper smelters in the United States would fall to between 7,000 and 9,000 Mg/yr (8,000 and 10,000 tons/year), realizing a 16 percent reduction.

Since reduction of sulfate emissions could be achieved by controlling the Phelps Dodge smelter mentioned above, it was specifically chosen as a model plant for cost analysis. Acid plants will be the only control method considered in cost analysis. Table 4.4-2 presents a description of the plant.

However, plant closures before 1988 are projected that may obviate the need for any additional controls. Although non-ferrous smelters were regulated under the 1977 Clean Air Act, some copper smelters qualified for a provisional waiver of the compliance date.[19] The ten year waiver expires January 1, 1988. Two smelters are projected to close before 1988--the Tennessee Chemical Company smelter in Copperhill, Tennessee and the Phelps Dodge smelter in Douglas, Arizona.[20,21] The latter is the model unit.

Six domestic smelters have closed since 1980, and three of these closed in 1985 alone. Table 4.4-3 presents a list of these closures. Smelter closures have reduced domestic capacity by 36 percent from the 1984 level. Future facilities have no impact because only one new smelter has been built since 1960 and no new construction is planned.[19]

If all previously mentioned smelter closures are realized, acid sulfate emissions would fall to about 1,800 to 3,600 Mg (2,000 to 4,000 tons) per year in 1988. This estimate is based on a 60 percent capacity factor and WG3B emission estimates.

4.5 COKE OVENS

Acid sulfate emissions from domestic coke ovens are reported to be 5,000 Mg (5,500 tons) per year (Table 3-1). Reference 22 indicates that these emissions originate almost exclusively from underfiring the ovens. A portion of coke oven off-gas, containing a high concentration of H_2S, is recycled to the coke oven battery as combustion fuel. This results in SO_x emissions.

TABLE 4.4-2. MODEL PLANT FOR PRIMARY COPPER SMELTERS

Capacity Mg/yr (tons/yr)	Process Equipment	Number Operating/ Stand-By	Control Device
115,200 (127,000)	Multihearth Roasters	17/7	Acid Plant
	Reverberatory Furnaces	3/0	
	Converters	3/2	

TABLE 4.4-3. DOMESTIC PRIMARY COPPER SMELTER CLOSURES

Company	Location	Capacity Mg/yr (tons/yr)	Date of Closure
Anaconda	Anaconda, Montana	127,000 (140,000)	1980
Kennecott	McGill, Nevada	45,500 (50,000)	1983
	Garfield, Utah	254,000 (280,000)	June 1985
Phelps Dodge	Morenci, Arizona	190,500 (210,000)	December 1984
	Ajo, Arizona	63,500 (70,000)	April 1985
ASARCO	Tacoma, Washington	90,500 (100,000)	March 1985

By-product coke plants account for about 98 percent of coke production in the U.S.[22] Many of these plants employ a desulfurization process to remove H_2S from coke oven off-gas before it is recycled. A demonstrated example of this process is the vacuum carbonate system. The vacuum carbonate system consists of a sodium carbonate absorption unit and an actifier. The absorber removes about 90 percent of the oven gas H_2S.[22] A portion of the desulfurized gas is then recycled to the coking battery for combustion. The H_2S-rich absorbent stream goes to the actifier where it is stripped to produce a concentrated H_2S stream. Claus plants are then used to recover sulfur from the "sweetened" H_2S stream. Material balances reported in Reference 22 indicate that desulfurization by the vacuum carbonate process can reduce SO_2 (and thus sulfate) emissions from underfiring by about 82 percent.

It is unclear from present information, whether the emissions estimate of 11 million pounds of acid sulfate per year takes into account existing desulfurization processes. Reference 22 presents an AP-42, uncontrolled emissions factor of 2 kg SO_2/Mg (4 lbs SO_2/ton) of coal charged for coke ovens underfired with untreated oven off-gas. Combining this with the WG3B (Reference 16) estimate that sulfate emissions equal 8.2 percent of SO_2 emissions yields 0.17 kg/Mg (0.33 lbs sulfate/ton coal) charged. This agrees closely with the emissions factor presented in Section A.1.3 of Appendix A. It could be inferred from these factors that emissions reductions realized from existing desulfurization processes are not included in the estimate. This would put actual acid sulfate emissions from domestic coke ovens well below 4,500 Mg (5,000 tons) per year. However, since this remains uncertain and the extent of existing desulfurization employed in the coking industry could not be clearly estimated, model units were developed.

The vacuum carbonate desulfurization process was chosen for control cost analysis because it is an established process and provides a high level of SO_x emissions reduction. The model vacuum carbonate systems are identical to those developed in Reference 22. Capacities, in terms of gas flow rate, are 0.57 million and 1.70 million std. m^3/day (20 million and 60 million SCFD). Model coke plants were sized proportionally with these systems using the bases presented in Table 4.5-1. Coke plant capacities, in terms of coal charged, are 2000 and 6000 Mg/day (2200 and 6600 tons/day).

TABLE 4.5-1. DESIGN BASES FOR MODEL COKE PLANTS[22]

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1. Coal charged is a bituminous mixture of one weight percent sulfur.
2. Coking cycle is 17 hours.
3. Plant operates 365 days per year.
4. 3.2 kilograms (6.5 lbs) of H_2S are generated per Mg (ton) of coal charged.
5. Vacuum carbonate system inlet H_2S concentration is 9.2 mg/m^3 (500 grains/100 SCF).
6. Coke oven operates at 900°C (1652°F) with 6 percent underfire excess air.

4.6 PRIMARY ALUMINUM

In Section 3 it was estimated that primary aluminum smelters in the U.S. emit approximately 5,900 Mg (6,500 tons) of HF per year. It was also indicated that acid sulfate emissions total 200 to 400 Mg (220 to 440 tons) per year. However, since the amount of sulfate emissions is not significant and HF emissions alone make primary aluminum smelters a significant source category, only the control of fluoride emissions is discussed further.

Total fluoride emissions from new, modified, or reconstructed aluminum smelters are limited by a standard of performance for new stationary sources (SPNSS) to the following levels:[23]

- 1 kg (2 lbs) of fluorides per ton of aluminum produced for plants using vertical (VSS) and horizontal stud Soderberg (HSS) cells;
- 0.9 kg (1.9 lbs) of fluorides per ton of aluminum produced for plants using center-worked (CWPB) and side-worked prebake (SWPB) cells;
- 0.05 kg (0.1 lb) of fluorides per ton of aluminum produced for anode bake plants.

Existing primary smelters are regulated by the Clean Air Act, which requires application of the best, adequately demonstrated control technology. In a study published by the U. S. Environmental Protection Agency (EPA) in 1979, the best control was determined to be an effective hooding system (which minimizes secondary emissions) in combination with wet or dry scrubbing of primary gases.[23]

Two types of dry scrubbers that have been demonstrated on aluminum smelter off-gases are fluid bed and injected alumina dry scrubbers. Both systems employ a suspended, or "fluidized," bed of alumina particles to absorb HF from the flue gas stream. Secondary (fugitive) emissions can be controlled with spray screen scrubbers. These devices are installed in roof ventilation systems and use a liquor spray to remove fluorides.

Table 4.6-1 presents the level of control existing on smelter potrooms in 1975. If the best demonstrated controls were applied, total fluoride emissions would be reduced by about 78 percent.[23] Assuming HF is controlled

TABLE 4.6-1. EXTENT OF POTROOM CONTROL AT PRIMARY ALUMINUM SMELTERS, 1975[23]

Cell Type[a]	Annual Capacity Mg Al (10^6 tons Al)	Percentage of Capacity Having:[b] At Least Primary Control	At Least Best Primary Control	Best Primary Control + Secondary Control[c]
CWPB	2.5 (2.7)	95	61	0
SWPB	0.6 (0.7)	81	79	59
HSS	0.9 (1.0)	100	83	0
VSS	0.5 (0.6)	100	100	33
All Cell Types	4.5 (5.0)	95	73	11

[a] CWPB = center-worked prebake cells, SWPB = side-worked prebake cells, HSS = horizontal stud Soderberg cells, VSS = vertical stud Soderberg cells

[b] Based on total fluorides (gaseous + particulate) emissions.

[c] Or, secondary control with equivalent overall control efficiency.

proportionally with total fluorides, national emissions would fall to approximately 1,400 Mg (1,500 tons) of HF per year.

Development of model plants for the domestic primary aluminum industry is not feasible. This is because plant type and configuration vary greatly among existing smelters, making actual control applications site specific. In lieu of model plants, control modules were taken from Reference 1 (Tables 4.6-2 and 4.6-3). These modules represent options for upgrading existing smelters, including removal of inadequate equipment and installation of the best demonstrated controls. Cost differences between alternatives for upgrading a specific smelter can be determined by evaluating various control scenarios. These are developed by choosing applicable control modules and summing their costs. The following approximations and assumptions were made in deriving the cost modules:[23]

- they are based on typical values of gas volumes to primary and secondary controls;
- it is assumed that the control costs per unit of production resulting from the modules will not vary significantly with plant size.

While this procedure is valid for specific plants, it can not be generically applied to the primary aluminum industry. To estimate a national retrofit cost would require access to control equipment inventories for all existing primary aluminum smelters. Appropriate control scenarios could then be applied and a total cost determined. In Section 5.6, an example retrofit control case is presented for each reduction cell type, and respective costs are updated to 1985 dollars. Cost effectiveness data, however, will only be valid for the specific smelters chosen and will not be representative of the industry as a whole.

TABLE 4.6-2. MODEL CONTROL MODULES FOR INSTALLING BEST AVAILABLE CONTROL TECHNOLOGY FOR PRIMARY ALUMINUM SMELTERS. CAPITAL COSTS[23] (MARCH 1985 DOLLARS)

Control Module*	Capital Cost $/Mg ($/ton) of annual capacity
VSS	
1. Install spray screen-secondary	166.94 (151.45)
CWPB and SWPB	
2. Lime treatment of cryolite bleed stream	4.17 (3.78)
3. Improve hooding	31.79 (28.84)
4. Install primary collection system	72.93 (66.16)
5. Install injected alumina dry scrubber-primary	112.93 (102.45)
6. Install spray screen secondary	119.24 (108.17)
7. Install fluidized bed dry scrubber-primary	129.55 (117.53)
8. Install anode bake plant controls	34.39 (31.20)
HSS	
9. Lime treatment of cryolite bleed stream	4.17 (3.78)
10. Improve hooding	31.79 (28.84)
11. Install spray screen-secondary	166.94 (151.45)

*VSS = vertical stud Soderberg cells; CWPB = center-worked prebake cells; SWPB = side-worked prebake cells; HSS = horizontal stud Soderberg cells

TABLE 4.6-3. MODEL CONTROL MODULES FOR REMOVAL OF INADEQUATE EXISTING CONTROL EQUIPMENT FOR PRIMARY ALUMINUM SMELTERS. CAPITAL COSTS[23]
(MARCH 1985 DOLLARS)

Control Module*	Capital Cost $/Mg ($/ton) of annual capacity
CWPB and SWPB	
1. Remove dry ESP-primary	13.17 (11.95)
2. Remove floating bed wet scrubber-primary	12.84 (11.65)
3. Remove coated bag filters-primary	24.11 (21.87)
4. Remove fluidized bed dry scrubber-primary	34.39 (31.20)
5. Remove multiple cyclone-secondary	14.04 (12.74)
6. Remove spry tower-primary	5.95 (5.40)
HSS	
7. Remove spray tower-primary	10.46 (9.49)
8. Remove floating bed scrubber-secondary	128.89 (116.93)

*CWPB = center-worked prebake cells; SWPB = side-worked prebake cells; HSS = horizontal stud Soderberg cells

4.7 MUNICIPAL SOLID WASTE INCINERATORS

HCL emissions from municipal solid waste (MSW) incinerators are generated by the combustion of chlorine-containing substances in the feed. These include chlorinated hydrocarbons and plastics, such as polyvinyl chloride. A typical analysis of MSW is presented in Table 4.7-1.

MSW incinerators generally fall into one of two categories--conventional or modular. The categories are identified mainly on the basis of waste throughput capacity. Conventional incinerators are large units with waste throughput capacities greater than 45 Mg/day (50 tons/day). Capacities of conventional units currently in operation can range up to 1800 Mg/day (2000 tons/day).[25] Modular, or packaged, incinerators are smaller units with less than 45 Mg/day (50 tons/day) capacity. In fact, most of these incinerators have MSW throughput capacities under 27 Mg/day (30 tons/day).[25] Reference 25 indicates that conventional units account for over 94 percent of annual MSW incineration in the U.S. As a result, only conventional units were considered for model development.

Incinerators can also be categorized with respect to heat recovery capability. Conventional units with heat recovery handle approximately 48 percent of domestic MSW throughput, while conventional units without heat recovery process about 46 percent.[25] Model incinerators, presented in Table 4.7-2, were developed using characteristics of both these types of units. The average capacity for conventional incinerators without heat recovery, presently operating in the U.S., is 381 Mg/day (420 tons/day). Units with heat recovery average about 800 tons/day in capacity.

No particular system or device can be identified as a demonstrated HCL control for use on domestic incinerators at the present time. Reference 5 suggests, however, that wet or dry scrubbing systems can achieve HCL removal efficiencies of at least 90 percent. The HCL control chosen for cost analysis is a wet scrubber employing a caustic soda (NaOH) based scrubbing liquor. A removal efficiency of 90 percent will be assumed.

TABLE 4.7-1. TYPICAL MUNICIPAL SOLID WASTE (MSW) ANALYSIS

Component	Analysis (% by weight)
Moisture	25.1
Carbon	25.2
Hydrogen	3.2
Oxygen	18.8
Nitrogen	0.4
Chlorine	0.3
Sulfur	0.1
Metal	8.7
Glass, Ceramics	12.2
Ash	6.0
TOTAL	100.0
Higher Heating Value	10,230 kJ/kg (4,400 Btu/lb)

Source: Reference 24.

TABLE 4.7-2. MODEL MUNICIPAL SOLID WASTE INCINERATORS

Type[a]	Conventional	Conventional
Heat Recovery[a]	No	Yes
Capacity:		
Waste Rate Mg/day (tons/day)[a]	381 (420)	726 (800)
Heat Input GJ/hr (MMBtu/hr)[b]	152 (150)	298 (293)
Capacity Factor[a]	0.77	0.86
Operating Parameters:		
Percent Excess Air[c]	150	80
Flue Gas Flow Rate m^3/s (ACFM)[d]	29 (61,450)	40 (84,770)
HCL Control Device	Sodium Scrubber (caustic based)	Sodium Scrubber (caustic based)
Percent HCL removal	90	90

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[a] Based on data from Reference 27.

[b] Based on MSW heating value of 1288 kJ/kg (4400 Btu/lb). Reference 24.

[c] Reference 5.

[d] Based on F-factor calculations.

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5.0 COST ANALYSIS

The model units developed in Section 4.0 were analyzed to determine the costs associated with retrofitting acidic material controls. Results of these analyses, including capital and annual costs, emissions reduction, and cost-effectiveness, are presented in this section. Most cost information was obtained through a literature search. Cost data for model industrial and utility boilers, however, were predominantly determined using computer modeling programs developed by Radian Corporation. Any applicable performance data that could be found is also presented.

Cost-effectiveness is determined as the annual cost of the retrofitted control system for removing a weight unit (Mg or ton) of acidic material. However, this cost-effectiveness calculation excludes the benefits of removing pollutants that are co-emitted with the acidic materials. The primary example is the removal of SO_2 by the control systems for acid sulfates, HCl, and HF. To gain a perspective of how SO_2 impacts the cost-effectiveness of shared control systems, the cost-effectiveness for SO_2 is also reported. Since SO_2 is emitted in substantially greater volume than the acidic materials, the cost-effectiveness of SO_2 is considerably lower.

Cost analyses of controls on industrial and utility boilers, Claus plants, fluid catalytic cracking units, primary copper smelters, coke ovens, primary aluminum smelters, and municipal solid waste incinerators are reported in the rest of this section.

5.1 INDUSTRIAL AND UTILITY BOILERS

Costs for emission controls on the model boilers were calculated using two computer cost models developed by Radian Corporation. Industrial control system costs were calculated by IBCOST, a program developed specifically for industrial boilers and controls for EPA's new source performance standards development.[1] To develop coal-fired utility emissions control costs, Radian Coal Use Cost Model (RCUCM) was employed. This model is based on work conducted for EPA's Air and Environmental Engineering Research Laboratory and is described in "Emission Controls for Coal-Fired Boilers: Design Cost Manual" [Radian Coporation, Research Triangle Park, North Carolina, February 14, 1984]. Algorithms in both programs determine costs from inputs such as economic factors, cost rates, boiler characteristics (e.g., heat input capacity, efficiency, capacity factor), and fuel analysis. Table 5.1-1 presents brief analyses of the fuels used in cost calculations. Sample output tables for IBCOST and RCUCM are presented in Appendix B. Economic bases and computer nomenclature are also provided where appropriate. Update factors were included as input in each computer run to bring costs to March 1985 dollars. These are based on Chemical Engineering (CE) plant cost indices for capital costs and Bureau of Labor Statistics (BLS) producer price indices for annual operating and maintenance costs. Oil-fired utility emissions control costs were taken from Reference 5 and updated to March 1985 dollars.

Costs for flue gas desulfurization (FGD) systems on industrial boilers and coal-fired utility boilers are based on input values for SO_2 removal efficiency, in addition to the inputs mentioned above. For the purpose of comparing cost-effectiveness, an SO_2 removal efficiency of 90 percent was chosen as an average value for all FGD systems. This value is based on test data found in literature, which is summarized in Table 5.1.2. Removal of HCL and HF is assumed to be 90 percent also, since concurrent control is expected.[8,9] Acid sulfate removal is assumed to be 35 percent for "wet" systems and 65 percent for lime spray dryers with fabric filters.[10] The capital cost for retrofitting control systems varies from about 1.1 to 2.0 times the cost of new systems, depending on site specific considerations. For this study, a retrofit factor of 1.3 times the capital cost for new control units was used. Limestone wet scrubber costs for oil-fired utility boilers were taken from Reference 11 and updated to March 1985 dollars. Capital and annual costs for industrial and utility FGD systems are listed in Tables 5.1-3 and 5.1-4.

Cost-effectiveness data for sulfate removal by industrial and utility FGD systems are presented in Tables 5-1.5 and 5.1-6. Table 5.1-7 shows the cost-effectiveness of controlling HCL and HF for all selected FGD systems. Cost-effectiveness for removal of acid sulfates, HCL, and HF is presented in Table 5.1-8. The total cost-effectiveness for removing SO_2, acid sulfates,

TABLE 5.1-1. ANALYSIS OF FUELS USED FOR MODEL COST CALCULATIONS

Fuel	Sulfur Content (wt. %)	Ash Content (wt. %)	Heating Value kJ/kg (Btu/lb)
High-sulfur coal[a]	3.23	12.0	27,200 (11,700)
Low-sulfur coal[b]	0.59	11.0	29,100 (12,500)
Distillate oil[c]	0.50	trace	45,350 (19,500)
Residual oil (Industrial)[c]	3.00	0.1	43,000 (18,500)
Residual oil (Utility)[d]	1.00	---	------

[a] Based on typical values for EPA Region 5, Type H-bituminous coal. Reference 1.

[b] Based on typical values for EPA Region 5, Type B-bituminous coal. Reference 1.

[c] Based on average values seen by industrial boilers. Reference 2.

[d] Average value seen by utility boilers. Reference 3.

TABLE 5.1-2. PERFORMANCE DATA FOR SELECTED FGD SYSTEMS

FGD	Fuel	No. of Tests	Average SO_2 Removal (%)	Source
Sodium-Based Scrubber	Coal	8[a]	92	Reference 5
	Oil	12[a]	97	Reference 5
Dual Alkali Scrubber	Coal	5[a]	91	Reference 5
	Oil	1[a]	92	Reference 5
Limestone Wet Scrubber	Coal	---	65-90[b]	Reference 6
Wellman-Lord System	Coal	3	90	Reference 7
Lime Spray Dryer[c]	Coal	10	83	Reference 5

[a] Verified as EPA approved test methods.

[b] Range of values for performance data rather than mean value.

[c] Data for industrial spray dryers without fabric filters. Total removal expected to increase 9 to 15 percent with fabric filter. Reference 5.

TABLE 5.1-3. COSTS OF FLUE GAS DESULFURIZATION SYSTEMS FOR INDUSTRIAL BOILER MODELS[a]

Control Device	Boiler Capacity GJ/hr (MMBtu/hr)	Fuel[b]	Total Capital Investment ($1000)	Total Operating and Maintenance ($1000/yr)	Total Annual Costs ($1000/yr)
Sodium-Based Scrubber	30.5 (30)	HSC	491	212	293
		LSC	340	123	180
		DO	293	112	160
		RO	406	166	233
	406 (400)	HSC	2097	1543	1875
		LSC	1371	450	677
		DO	1196	333	532
		RO	1691	985	1257
Dual Alkali Scrubber	30.5 (30)	HSC	1650	371	642
		LSC	1102	306	486
		DO	959	295	445
		RO	1405	338	568
	406 (400)	HSC	4982	1231	2044
		LSC	3351	553	1105
		DO	2895	474	929
		RO	4200	876	1564

TABLE 5.1-3. COSTS OF FLUE GAS DESULFURIZATION SYSTEMS FOR INDUSTRIAL BOILER MODELS[a] (Continued)

Control Device	Boiler Capacity GJ/hr (MMBtu/hr)	Fuel	Total Capital Investment ($1000)	Total Operating and Maintenance ($1000/yr)	Total Annual Costs ($1000/yr)
Lime Spray Dryer[c]	30.5 (30)	HSC	1798	399	693
		LSC	1338	337	555
		DO	1183	326	518
		RO	1531	364	614
	406 (400)	HSC	7732	1495	2760
		LSC	5733	737	1682
		DO	4584	556	1312
		RO	6084	999	1998

[a] Costs in March 1985 dollars produced by IBCOST Computer Model.

[b] HSC = high-sulfur coal; LSC = low-sulfur coal; DO = distillate oil; RO = residual oil.

[c] Includes cost for particulate matter control.

TABLE 5.1-4. COSTS OF FLUE GAS DESULFURIZATION SYSTEMS FOR UTILITY BOILER MODELS[a]

Control Device	Boiler Heat Input Capacity GJ/hr (MMBtu/hr)	Fuel	Total Capital Investment ($1000)	Total Operating and Maintenance[b] ($1000/yr)	Total Annual Costs ($1000/yr)[c]
Limestone Wet Scrubber	2,031 (2,000)	HSC	69,094	7,660	26,016
		LSC	55,548	6,258	21,067
		RO	32,592	NA	11,935
	5,078 (5,000)	HSC	125,780	13,027	45,979
		LSC	105,678	10,341	37,719
		RO	62,926	NA	23,448
Wellman-Lord Scrubbing System	2,031 (2,000)	HSC	105,460	10,604	38,070
		LSC	68,492	7,178	25,164
	5,078 (5,000)	HSC	202,258	21,500	74,767
		LSC	133,276	14,344	49,534
Lime Spray Dryer (with fabric filter)	2,031 (2,000)	HSC	67,790	7,696	26,217
		LSC	56,212	5,342	19,825
	5,078 (5,000)	HSC	134,137	14,940	50,613
		LSC	108,822	9,387	36,940

[a] Costs for systems employed on coal-fired boilers calculated using RCUCM. Costs for limestone wet scrubbers on oil-fired boilers taken from Reference 11 and updated to March 1985 dollars.

[b] NA = Not available.

[c] Costs for systems on coal-fired units are levelized costs over 20 year equipment life.

TABLE 5.1-5. COST-EFFECTIVENESS DATA FOR INDUSTRIAL FGD MODEL UNITS: SULFATE

Boiler Heat Input Capacity GJ/hr (MMBtu/hr)	Fuel[a]	Control Device[b]	Controlled Sulfate Emissions Mg/yr (tons/yr)[c]	Total Annual Cost ($1000/yr)[d]	Cost Effectiveness $/Mg ($/ton) Sulfate Removed
30.5 (30)	HSC	SS	2.41 (2.65)	293	122,000 (110,000)
		DA		642	266,000 (242,000)
		LSD	4.48 (4.93)	693	155,000 (141,000)
	LSC	SS	2.26 (2.48)	180	80,000 (73,000)
		DA		486	216,000 (196,000)
		LSD	4.19 (4.61)	555	132,000 (120,000)
	DO	SS	0.45 (0.49)	160	359,000 (327,000)
		DA		445	999,000 (908,000)
		LSD	0.83 (0.91)	518	626,000 (569,000)
	RO	SS	0.47 (0.52)	233	493,000 (448,000)
		DA		568	1,202,000 (1,092,000)
		LSD	0.87 (0.96)	614	704,000 (640,000)
406 (400)	HSC	SS	32.16 (35.38)	1,875	58,000 (53,000)
		DA		2,044	64,000 (58,000)
		LSD	59.72 (65.70)	2,760	46,000 (42,000)
	LSC	SS	30.10 (33.11)	677	22,000 (20,000)
		DA		1,105	37,000 (33,000)
		LSD	50.82 (55.90)	1,682	33,000 (30,000)
	DO	SS	5.95 (6.55)	532	89,000 (81,000)
		DA		929	156,000 (142,000)
		LSD	11.06 (12.16)	1,312	119,000 (108,000)
	RO	SS	6.28 (6.91)	1,257	200,000 (182,000)
		DA		1,565	249,000 (226,000)
		LSD	11.65 (12.81)	1,998	172,000 (156,000)

[a] HSC = high-sulfur coal/LSC = Low-sulfur coal; DO = distillate oil; RO = residual oil.

[b] SS = sodium-based scrubber; DA = dual alkali scrubber; LSD = lime spray dryer (with fabric filter)

[c] Based on 35 percent $SO_4^=$ removal for SS and DA; 65 percent removal for LSD (Reference 10) and emission factors from Reference 12.

[d] All costs in March 1985 dollars, calculated by IBCOST model.

TABLE 5.1-6. COST-EFFECTIVENESS DATA FOR UTILITY FGD MODEL UNITS: SULFATE

Boiler Heat Input Capacity GJ/hr (MMBtu/hr)	Fuel[a]	Control Device[b]	Controlled Sulfate Emissions Mg (tons/yr)[c]	Total Annual Cost ($1000/yr)[d]	Cost Effectiveness $/Mg ($/ton) Sulfate Removed
2,031 (2000)	HSC	LWS	22.9 (25.2)	26,016	1,135,000 (1,032,000)
		WL		38,070	1,662,000 (1,511,000)
		LSD	42.5 (46.8)	26,217	616,000 (560,000)
	LSC	LWS	21.5 (23.5)	21,067	982,000 (893,000)
		WL		25,164	1,173,000 (1,066,000)
		LSD	39.8 (43.8)	19,825	498,000 (453,000)
	RO	LWS	41.0 (45.1)	11,935	292,000 (265,000)
5,078 (5000)	HSC	LWS	57.3 (63.0)	45,979	802,000 (729,000)
		WL		74,767	1,305,000 (1,187,000)
		LSD	106.4 (117.0)	50,613	476,000 (337,000)
	LSC	LWS	53.6 (59.0)	37,719	703,000 (639,000)
		WL		49,534	924,000 (840,000)
		LSD	99.5 (109.5)	36,940	371,000 (337,000)
	RO	LWS	102.5 (112.7)	23,448	229,000 (208,000)

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[a] HSC = high-sulfur coal/LSC = Low-sulfur coal; DO = distillate oil; RO = residual oil.

[b] LWS = limestone wet scrubber; WL = Wellman-Lord System; LSD = lime spray dryer (with fabric filter)

[c] Based on 35 percent $SO_4^=$ removal for LWS and WL; 65 percent removal for LSD (Reference 10) and emission factors from Reference 12.

[d] Costs in March 1985 dollars. Coal-fired unit costs calculated by RCUCM Model; oil-fired costs taken from Reference 11.

TABLE 5.1-7. FGD COST-EFFECTIVENESS FOR COAL-FIRED MODEL UNITS: HCL AND HF CONTROL

Boiler Heat Input Capacity GJ/hr (MMBtu/hr)	Fuel[a]	FGD[b]	Total Annual Cost ($1000/yr)	Controlled HCL Emissions Mg/yr (tons/yr)[c]	Cost Effectiveness $/Mg ($/ton HCL removed)	Controlled HF Emissions Mg/yr (tons/yr)[c]	Cost Effectiveness $/Mg ($/ton HF removed)
30.5 (30)	HSC	SS	293	5.1 (5.6)	57,600 (52,300)	1.0 (1.1)	293,700 (266,400)
		LSD	693		136,100 (123,700)		694,400 (630,000)
		DA	642		126,100 (114,600)		643,300 (583,600)
	LSC	SS	180		35,400 (32,100)		180,300 (163,600)
		LSD	555		109,000 (99,100)		556,100 (504,500)
		DA	486		95,500 (87,800)		487,000 (441,800)
406 (400)	HSC	SS	1,875	67.2 (73.9)	27,900 (25,400)	8.4 (9.2)	224,200 (203,800)
		LSD	2,760		41,100 (37,300)		330,000 (300,000)
		DA	2,044		30,400 (27,700)		244,400 (222,200)
	LSC	SS	677		10,100 (9,200)		80,900 (73,600)
		LSD	1,682		25,000 (22,800)		201,100 (182,800)
		DA	1,105		16,400 (15,000)		132,100 (120,100)
2,031 (2,000)	HSC	LWS	26,016	338.9 (372.8)	76,800 (69,800)	40.5 (44.5)	643,100 (584,600)
		LSD	26,217		77,400 (70,300)		648,100 (589,100)
		WL	38,070		112,300 (102,100)		941,100 (855,500)
	LSC	LWS	21,067		62,200 (56,500)		520,000 (473,400)
		LSD	19,825		58,500 (53,200)		490,100 (445,500)
		WL	25,164		74,200 (67,500)		622,000 (565,500)
5,078 (5,000)	HSC	LWS	45,979	847.3 (932.0)	54,300 (49,300)	101.1 (111.2)	454,800 (413,500)
		LSD	50,613		59,700 (54,300)		500,700 (455,200)
		WL	74,767		88,200 (80,200)		739,600 (672,400)
	LSC	LWS	37,719		44,500 (40,500)		373,100 (339,200)
		LSD	36,940		43,600 (39,600)		365,400 (332,200)
		WL	49,534		58,500 (53,100)		400,000 (445,400)

[a] HSC = high-sulfur coal; LSC = low-sulfur coal.

[b] SS = sodium scrubber; LSD = lime spray dryer; DA = dual alkali scrubber; LWS = limestone wet scrubber; WL - Wellman-Lord System.

[c] Based on 90 percent control and emission factors from Reference 13.

TABLE 5.1-8. COST-EFFECTIVENESS FOR REMOVAL OF ACIDIC MATERIALS BY MODEL FGD SYSTEMS

Boiler Heat Input Capacity GJ/hr (MMBtu/hr)	Fuel[a]	Control Device[b]	Total Controlled Acidic Materials Mg/yr (tons/yr)[c]	Total Cost-Effectiveness $/Mg ($/ton) (acidic material removed)
30.5 (30)	HSC	SS	7.5 (8.2)	39,300 (35,700)
		DA		86,100 (78,300)
		LSD	9.6 (10.5)	72,600 (66,000)
	LSC	SS	7.4 (8.1)	24,400 (22,200)
		DA		66,000 (60,000)
		LSD	9.3 (10.2)	59,900 (54,400)
	DO	SS	0.4 (0.5)	359,000 (327,000)
		DA		999,000 (908,000)
		LSD	0.8 (0.9)	626,000 (569,000)
	RO	SS	0.5 (0.5)	492,800 (448,000)
		DA		1,200,000 (1,090,000)
		LSD	0.9 (1.0)	704,000 (640,000)
406 (400)	HSC	SS	99.4(109.3)	18,900 (17,200)
		DA		20,600 (18,700)
		LSD	126.9(139.6)	21,700 (19,800)
	LSC	SS	97.3(107.0)	7,000 (6,300)
		DA		11,400 (10,300)
		LSD	118.0(129.8)	14,300 (13,000)
	DO	SS	5.9 (6.5)	89,000 (81,000)
		DA		156,000 (142,000)
		LSD	11.1 (12.2)	119,000 (108,000)
	RO	SS	6.3 (6.9)	200,000 (182,000)
		DA		249,000 (226,000)
		LSD	11.6 (12.8)	172,000 (156,000)

TABLE 5.1-8. COST-EFFECTIVENESS FOR REMOVAL OF ACIDIC MATERIALS BY MODEL FGD SYSTEMS (Continued)

Boiler Heat Input Capacity GJ/hr (MMBtu/hr)	Fuel[a]	Control Device[b]	Total Controlled Acidic Materials Mg/yr (tons/yr)[c]	Total Cost-Effectiveness $/Mg ($/ton) (acidic material removed)
2,031 (2,000)	HSC	LWS	402.3 (442.5)	64,700 (58,800)
		WL		94,600 (86,000)
		LSD	421.9 (464.1)	62,100 (56,500)
	LSC	LWS	400.8 (440.9)	52,600 (47,800)
		WL		62,800 (57,100)
		LSD	419.2 (461.1)	47,300 (43,000)
	RO	LWS	41.0 (45.1)	291,100 (264,600)
5,078 (5,000)	HSC	LWS	1,005.7 (1,106.2)	45,700 (41,600)
		WL		74,300 (67,600)
		LSD	1,054.8 (1,160.2)	48,000 (43,600)
	LSC	LWS	1,002.0 (1,102.2)	37,600 (34,200)
		WL		49,400 (44,900)
		LSD	1,048.0 (1,152.7)	35,300 (32,000)
	RO	LWS	102.5 (112.7)	229,000 (208,000)

[a] HSC = high-sulfur coal; LSC = Low-sulfur coal; DO = distillate oil; RO = residual oil.

[b] SS = sodium scrubber; DA = dual alkali scrubber; LSD = lime spray dryer (with fabric filter); LWS = limestone wet scrubber; WL = Wellman-Lord system.

[c] Includes acid sulfates and acid gases (HCL and HF) for coal-fired units; only acid sulfates are included for oil-fired units.

[d] Costs in March 1985 dollars. Coal-fired unit costs calculated by RCUCM Model; oil-fired costs taken from Reference 11.

HCl, and HF is given in Table 5-1.9. Sodium-based scrubbers applied to 406 GJ/hr (400 x 10^6 Btu/hr) industrial boilers firing low-sulfur coal exhibit the greatest cost-effectiveness at $7000/Mg ($6300/ton) of acidic material removed. Dual alkali scrubbers applied to 30.5 GJ/hr (30 x 10^6 Btu/hr) residual oil-fired boilers are the least cost-effective, since sulfates are the only material controlled. These units cost $1.20 million/Mg ($1.09 million/ton) of sulfate removed.

Costs for NO_x controls on industrial boilers were calculated using IBCOST. Since no nitrate emission data were available, the cost of controls is based on the reduction of NO_x. Proportionate reduction of nitrates is expected; however, since nitrate emissions make up only a portion of total NO_x emissions, the actual cost-effectiveness of nitrate emissions reduction is higher than the calculated NO_x reduction cost-effectiveness. Utility NO_x control costs for coal and oil-fired boilers were taken from References 13 and 14, respectively, and updated to March 1985 dollars. Table 5.1-10 presents total capital and annual costs, NO_2 emissions reductions, and cost-effectiveness for each control method. It was determined from emission factors in Reference 13 that the 30 x 10^6 Btu/hr boilers and the 400 x 10^6 Btu/hr oil-fired boilers would not require additional NO_x control to meet the current New Source Performance Standard (NSPS) for NO_x emissions. Therefore, they are not included in the NO_x control cost analysis.

The most cost-effective NO_x control technique is low excess air (LEA) applied to the 5000 x 10^6 Btu/hr oil-fired boiler. This method requires only $1 per ton of reduced NO_x emissions. Overfire air (OFA) ports employed on the 2000 x 10^6 Btu/hr oil-fired boiler and LEA applied to the 400 x 10^6 Btu/hr boiler firing high-sulfur coal are the least cost-effective. These techniques cost approximately $132/Mg ($120/ton) of reduced NO_x emissions. The wide range of LEA costs for the 400 x 10^6 Btu/hr boiler can be accounted for by the difference in fuel costs. LEA generates fuel savings, thus, the lower priced, high-sulfur coal will produce less savings.

5.2 CLAUS PLANTS

The model Claus plants developed in Section 4.2 were analyzed with respect to capital investment, net annual cost, and cost-effectiveness of

TABLE 5.1-9. TOTAL COST-EFFECTIVENESS FOR REMOVAL OF SO_2 AND ACIDIC MATERIALS BY MODEL FGD SYSTEMS

Boiler Heat Input Capacity GJ/hr (MMBtu/hr)	Fuel[a]	Control Device[b]	Total Controlled SO_2 and Acidic Materials Mg/yr (tons/yr)[c]	Total Cost-Effectiveness $/Mg ($/ton) (removed)
30.5 (30)	HSC	SS	362 (398)	810 (740)
		DA		1,770 (1,610)
		LSD	363 (400)	1,910 (1,730)
	LSC	SS	68 (75)	2,640 (2,400)
		DA		7,130 (6,480)
		LSD	70 (77)	7,930 (7,210)
	DO	SS	33 (36)	4,890 (4,440)
		DA		13,600(12,360)
		LSD	34 (37)	15,400(14,000)
	RO	SS	210 (230)	1,110 (1,010)
		DA		2,720 (2,470)
		LSD	211 (231)	2,920 (2,660)
406 (400)	HSC	SS	4,863 (5,349)	390 (350)
		DA		420 (380)
		LSD	4,891 (5,380)	560 (510)
	LSC	SS	906 (997)	750 (680)
		DA		1,220 (1,110)
		LSD	927 (1,020)	1,810 (1,650)
	DO	SS	451 (496)	1,180 (1,070)
		DA		2,060 (1,870)
		LSD	457 (502)	2,870 (2,610)
	RO	SS	2,797 (3,077)	450 (410)
		DA		560 (510)
		LSD	2,803 (3,083)	710 (640)

TABLE 5.1-9. TOTAL COST-EFFECTIVENESS FOR REMOVAL OF SO_2 AND ACIDIC MATERIALS BY MODEL FGD SYSTEMS (Continued)

Boiler Heat Input Capacity GJ/hr (MMBtu/hr)	Fuel[a]	Control Device[b]	Total Controlled SO_2 and Acidic Materials Mg/yr (tons/yr)[c]	Total Cost-Effectiveness $/Mg ($/ton) (removed)
2,031 (2,000)	HSC	LWS	22,920 (25,212)	1,130 (1,030)
		WL		1,660 (1,510)
		LSD	22,940 (25,234)	1,140 (1,040)
	LSC	LWS	4,246 (4,671)	4,960 (4,510)
		WL		5,930 (5,390)
		LSD	4,264 (4,691)	4,650 (4,230)
	RO	LWS	5,065 (5,572)	2,350 (2,140)
5,078 (5,000)	HSC	LWS	57,300 (63,030)	800 (730)
		WL		1,300 (1,190)
		LSD	57,350 (63,085)	880 (800)
	LSC	LWS	10,616 (11,677)	3,550 (3,230)
		WL		4,670 (4,240)
		LSD	10,661 (11,727)	3,460 (3,150)
	RO	LWS	12,664 (13,930)	1,850 (1,680)

[a] HSC = high-sulfur coal; LSC = Low-sulfur coal; DO = distillate oil; RO = residual oil.

[b] SS = sodium scrubber; DA = dual alkali scrubber; LSD = lime spray dryer (with fabric filter); LWS = limestone wet scrubber; WL = Wellman-Lord system.

[c] Includes acid sulfates and acid gases (HCL and HF) for coal-fired units; only acid sulfates are included for oil-fired units.

LSD. Reference 10.

[d] Costs in March 1985 dollars. Coal-fired unit costs calculated by RCUCM Model; oil-fired costs taken from Reference 11.

TABLE 5.1-10. NO_x CONTROL COSTS FOR MODEL BOILER UNITS

Boiler Type	Heat Input Capacity GJ/hr (MMBtu/hr)	NO_x Control[c]	Fuel	Total Capital Investment ($)	Total Annual Costs ($)	NO_2 Emissions Reductions Mg/yr (tons/yr)[d]	Cost-Effectiveness $/Mg ($/ton) (NO_2 controlled)
Industrial/ wall fired	406 (400)	LEA	HSC	163,000	17,000	129 (142)	132 (120)
			LSC	162,000	1,000	120 (132)	9 (8)
		OFA	Coal	148,000	29,000	258 (284)	112 (102)
	2,031 (2,000)	LNB	Coal	1,480,000	264,000	2146 (2365)	124 (112)
		LEA	Coal	350,000	4,000	644 (710)	7 (6)
			Oil	143,000	1,000	536 (591)	2 (2)
		OFA	Coal	412,000	124,000	1288 (1420)	96 (87)
			Oil	314,000	94,000	715 (788)	131 (119)
	5,078 (5,000)	LNB	Coal	2,135,000	380,000	5364 (5913)	8 (7)
		LEA	Coal	505,000	5,000	1609 (1774)	3 (3)
			Oil	206,000	2,000	1341 (1478)	1 (1)
		OFA	Coal	595,000	180,000	3219 (3548)	56 (51)
			Oil	491,000	147,000	1788 (1971)	83 (75)

[a] Costs produced by IBCOST Computer Model.

[b] Data for coal-fired boilers taken from Reference 13. Data for oil-fired boilers taken from Reference 14. All costs updated to March 1985 dollars using CE Plant Cost indices.

[c] LEA = low excess air; OFA = overfire air; LNB = low NO_x burners.

[d] Based on emission factors and estimated reduction efficiencies, References 13 and 14.

reducing sulfate emissions. All costs for the 10 and 100 Mg/day (11 and 110 tons/day) model plants were taken from Reference 15 and updated to March 1985 dollars using CE plant cost indices (capital costs) and BLS producer price indices (annual costs). Costs for the 250 LT/D plant were derived using the procedure outlined in Reference 15, Appendix A.

Capital cost estimates are derived from an analysis of data furnished by equipment vendors and operating plants. Annual costs are based on the assumptions and design parameters listed in Table 5.2-1. Both capital and annual costs are presented in Table 5.2-2. Credits are given for sulfur and steam produced by the Claus plants and control systems. The difference between total credits and total annual cost is the net annual cost for the model plant. For the two larger units, this becomes an annual profit for the Claus plant.

The control system selected for each controlled model plant is an amine tail-gas treatment system. Sulfur recovery (and, thus, SO_2 control) is increased from about 96 percent to 99.9 percent with the addition of such systems. Since this process operates under reducing conditions, as mentioned in Section 4.2, control of sulfates is assumed proportional to SO_2 control. Cost-effectiveness data presented in Table 5.2-3 reflect this assumption. Results indicate that cost-effectiveness improves with increasing plant size. This could be due to increased sulfur recovery with larger amine control units. Cost-effectiveness for the 10, 100, and 250 Mg/day (11, 110, and 276 tons/day) model plants are $220,000, $72,000, and $50,000 per ton sulfate removed, respectively. Cost-effectiveness for SO_2 removal is only 1 percent of the sulfate cost-effectiveness values as shown in Table 5.2-4.

5.3 FLUID CATALYTIC CRACKING

It was estimated in Section 4.3 that total acid sulfate emissions from fluid catalytic cracking (FCC) units in the U.S. could be reduced by about 32 percent if sodium scrubbers were applied to existing units. This section presents the results of a cost analysis performed to evaluate the cost-effectiveness of retrofitting sodium-based scrubbers to FCC model units. The analysis was based on the NSPS mentioned in Section 4.3.

TABLE 5.2-1. ASSUMPTIONS AND BASES FOR ANNUAL COSTS[a]

1. All plants handle acid gas consisting of 80 percent H_2S, 10 percent CO_2, 4.5 percent NH_3, 0.5 percent hydrocarbons, and 5 percent moisture. Acid gas streams are saturated at 109°F and 24.7 psia.

2. Claus plants use high efficiency alumina catalysts for maximum sulfur recovery.

3. Claus plants consume 4100 kPa (600 psig) steam and generate 1700 kPa (250 psig) and 100 kPa (15 psig) steam, with 3-stage plants also generating 350 kPa (50 psig) steam.

4. With waste heat recovery, 600 psig steam is also generated, while tail-gas treaters are net consumers of 50 psig steam.

5. Capital recovery costs are based on 15 year equipment life at 10 percent interest. Capital recovery factor = 0.1315.

6. Plants operate 350 days per year.

7. Unit prices:

	Item	Cost[b]
4100 kPa	(600 psig) steam	\$0.016/kg (\$7.25/1000 lb)
1700 kPa	(250 psig) steam	\$0.015/kg (\$6.75/1000 lb)
350 kPa	(50 psig) steam	\$0.013/kg (\$5.75/1000 lb)
100 kPa	(15 psig) steam	\$0.010/kg (\$4.50/1000 lb)
	Sulfur	\$120/Mg (\$109/ton)

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[a] Source: Reference 15.

[b] Given as presented in Reference 15. All annual costs updated in actual calculations using BLS producer price indices.

TABLE 5.2-2. COSTS FOR MODEL CLAUS PLANTS[a]

	Model Size (LT/D)		
	10	100[b]	250[b]
Uncontrolled			
Total Capital Investment ($)	2,630,000	6,470,000	10,550,000
Total Annual Cost ($/yr)	737,400	2,113,700	3,894,900
Total Credits[c] ($/yr)	519,400	5,830,300	14,577,200
Net Annual Cost ($/yr)	218,000	(3,716,600)	(10,682,300)
Controlled[d]			
Total Capital Investment ($)	5,130,000	10,960,000	17,830,000
Total Annual Cost ($/yr)	1,569,500	3,798,400	6,938,800
Total Credits[c] ($/yr)	569,500	5,870,100	14,697,200
Net Annual Cost ($/yr)	967,000	(2,071,700)	(7,758,400)

---

[a] Costs taken from Reference 15 and updated to March 1985 dollars.

[b] Parentheses ( ) indicate profits.

[c] Includes credits for sulfur and steam produced.

[d] Control in all cases is amine tail-gas treatment.

TABLE 5.2-3. COST-EFFECTIVENESS FOR CONTROL OF MODEL CLAUS PLANTS - SULFATE

Model Size Mg/D (TPD)	Annual Cost (\$/yr)[a]	Annual Acid Sulfate Emissions Reduction Mg/yr (tons/yr)[b]	Cost-Effectiveness \$/Mg (\$/ton) (acid sulfate removed)
10 (11)	749,000	3.1 (3.4)	242,800 (220,300)
100 (110)	1,644,900	21.3 (23.5)	77,200 (70,000)
250 (276)	2,923,900	53.3 (58.7)	54,900 (49,800)

[a] Cost of amine tail-gas treatment. Calculated as the difference between controlled and uncontrolled plant costs. March 1985 dollars. Reflects profit/loss for 100 and 250 Mg/D (110 and 276 TPD) units.

[b] Based on SO_2 removal data from Reference 15 and the WG3B estimate that acid sulfate emissions equal one percent of SO_2 emissions.

TABLE 5.2-4. COST-EFFECTIVENESS FOR CONTROL OF MODEL CLAUS PLANTS - SO_2

Model Size Mg/D (TPD)	Annual Cost ($/yr)[a]	Annual SO_2 Emissions Reduction Mg/yr (tons/yr)[b]	Cost-Effectiveness $/Mg ($/ton) (SO_2 removed)
10 (11)	749,000	310 (340)	2420 (2200)
100 (110)	1,644,900	2130 (2350)	770 (700)
250 (276)	2,923,900	5330 (5870)	550 (500)

[a] Cost of amine tail-gas treatment. Calculated as the difference between controlled and uncontrolled plant costs. March 1985 dollars. Reflects profit/loss for 100 and 250 Mg/D (110 and 276 TPD) units.

[b] Based on SO_2 removal data from Reference 15 and the WG3B estimate that acid sulfate emissions equal one percent of SO_2 emissions.

Table 5.3-1 presents a list of sodium-based scrubbers currently operating on FCC units with their locations and performance data. Two types of sodium-based scrubbers which are presently in use on domestic FCC unit regenerators are jet ejector venturis (JEV) and high energy venturis (HEV). Jet ejector venturis are generally used on FCC units equipped with carbon monoxide boilers. High energy venturis are used on FCC units that utilize high temperature regeneration or conventional promoted regeneration.[16] JEV scrubbers are currently employed on five FCC units at three refineries, representing 8.5 percent of U.S. fresh feed capacity. HEV scrubbers have been applied to two FCC units at two refineries, accounting for 2.5 percent of domestic fresh feed capacity.

Acid sulfate removal efficiency data for sodium-based scrubbers were not available. Reference 12 estimates 35 percent sulfate control for flue gas desulfurization systems. Sulfur dioxide removal efficiencies, however, were reported for two jet ejector venturis and two high energy venturis. Both types of scrubbers achieve an average SO_2 removal efficiency of 94 percent.

Sodium-based venturi scrubbers applied to FCC units are also effective in controlling particulate matter (PM) emissions. Removal of PM is accomplished via inertial impaction of scrubbing liquor with entrained particulates. In two separate EPA Method 5 testing series at one refinery, average PM removal efficiencies of 83 and 95 percent were achieved.[16]

Capital costs for the sodium-based scrubbing systems chosen for analysis are presented in Table 5.3-2. These costs are based on the regenerator flue gas flow rate. The inlet SO_x concentration has no impact. The total capital costs of the JEV systems for the 2,500 and 8,000 m^3/sd (15,725 and 50,320 bbl/sd) model units are $8.4 million and $14.8 million, respectively. The HEV systems require respective total capital investments of $6.1 million and $10.7 million for the same model units. JEV scrubber costs are higher than those for HEV scrubbers because JEV systems require additional piping, pumps, and spray nozzles. All costs were taken from Reference 16 and updated to March 1985 dollars using Chemical Engineering (CE) plant cost indices. A retrofit factor of 1.3 times the sum of total direct and indirect costs plus contingency was also applied.[17]

TABLE 5.3-1. PERFORMANCE DATA FOR SODIUM-BASED SCRUBBERS ON FCC UNIT REGENERATORS[16]

Refinery/Location	Scrubber Type	FCC Fresh Feed[a] Capacity m^3/sd (bbl/sd)	SO_2 Removal[b] Efficiency
Exxon, Bayway, New Jersey	Two jet ejector venturis for the FCC unit	19,100 (120,000)	NA
Exxon, Baton Rouge, Louisiana (2 FCC units)	One jet ejector venturi system for both FCC units	24,600 (155,000)	NA
Exxon, Baytown, Texas (2 FCC units)	One jet ejector venturi for each FCC unit	24,600 (155,000)	94 94
Marathon, Garyville, Louisiana	High energy venturi	11,900 (75,000)	93
Southwestern, Corpus Christi, Texas	High energy venturi	7,500 (47,000)	95

[a] bbl/sd = barrels per stream day

[b] For the purpose of this study, it is assumed that the acid sulfates removal efficiency is 35 percent. Reference 12.

TABLE 5.3-2. CAPITAL COSTS FOR SODIUM-BASED SCRUBBING SYSTEMS APPLIED TO FLUID CATALYTIC CRACKING UNITS[a]

	High Energy Venturis		Jet Ejector Venturis	
	2500 m^3/sd (15,725 bbl/sd) Model Unit	8000 m^3/sd (50,320 bbl/sd) Model Unit	2500 m^3/sd (15,725 bbl/sd) Model Unit	8000 m^3 sd (50,320 bbl/sd) Model Unit
Total Direct Costs[b]	2.7	4.8	3.9	6.7
Indirect Costs	1.2	2.0	1.5	2.9
Total Direct and Indirect Costs	3.9	6.8	5.4	9.5
Contingency[c]	0.8	1.4	1.1	1.9
Retrofit Cost[d]	1.4	2.5	1.9	3.4
Total Capital Cost	6.1	10.7	8.4	14.8

[a] Costs in millions of dollars; adjusted to the 1st quarter, 1985. Reference 16.

[b] Materials and labor.

[c] Twenty percent of total direct and indirect costs.

[d] Assumed to be 30 percent of (Total Direct and Indirect Cost + Contingency).

The annual costs associated with these systems were also taken from Reference 16 and updated to March 1985 dollars using BLS producer price indices. Some of the assumptions and bases used to derive the annual costs are listed in Table 5.3-3. Tables 5.3-4 and 5.3-5 present the annual costs of the HEV and JEV scrubbers, respectively. Total annual cost increases with increasing unit size and increasing feed stream sulfur content. This results from greater requirements of sorbent at higher sulfur loadings. Annual costs for JEV scrubbers are also higher than those for HEV scrubbers. This is due primarily to the greater electrical demand of JEV systems.[16]

Cost-effectiveness data are presented in Tables 5-3.6 and 5-3.7. When caustic soda is used as the sorbent, cost-effectiveness ranges from \$47,000/Mg (\$43,000/ton) sulfate removed for the large HEV-equipped unit using a higher sulfur feed to \$123,000/Mg (\$112,000/ton) sulfate removed for the small JEV-equipped unit employing a medium sulfur feed.

5.4 PRIMARY COPPER

The model smelter chosen for cost analysis is based on the plant size and configuration of the Phelps Dodge smelter in Douglas, Arizona. It employs two stacks. One handles converter off-gases, while the other vents roaster and reverberatory furnace off-gases.[19] Only the control of converter off-gases was analyzed to determine cost-effectiveness. The acid plant size is based on the converter flue gas flow rate of 125 m^3/s (264,000 scfm).

It should be noted that some sulfuric acid mist is emitted from acid plants. However, electrostatic precipitators are generally used to remove acid mist at the plant inlet, and mist eliminators are employed after each absorption stage. For this reason, cost-effectiveness calculations assume that sulfate removal is proportional to SO_2 removal.

Table 5.4-1 presents the capital and annual costs of both single-stage (SCSA) and dual-stage (DCDA) acid plants. Total capital investments for the SCSA and DCDA units are \$48.7 million and \$55.6 million, respectively. Total annual costs are \$12.3 million and \$14.0 million, respectively. Cost-effectiveness data is given in Table 5.4-2 and 5.4-3. The SCSA plant costs \$9,800/Mg (\$8,900/ton) sulfate removed while the DCDA plant requires

TABLE 5.3-3. BASES AND ASSUMPTIONS FOR DETERMINING ANNUAL COSTS OF SODIUM-BASED SCRUBBING SYSTEMS APPLIED TO FLUID CATALYTIC CRACKING UNITS[16]

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1. Maintenance includes material, labor, and overhead and equals 1.5 percent of the total capital cost.

2. Indirect operating costs include taxes, insurance, and administration and equal 4 percent of the total capital cost.

3. The capital recovery factor (CRF) is based on an interest rate of 10 percent and a service life of 15 years (CRF = 0.1315).

4. The amount of caustic soda or soda ash consumed is proportional to the amount of SO_x removed.

5. The system operates 357 days per year.

6. Costs for treating the scrubber purge stream are included in waste disposal costs. The purge treatment unit consists of below-ground ponding for sedimentation of suspended solids and surface aerators to reduce chemical oxygen demand.

TABLE 5.3-4. ANNUAL COSTS FOR HIGH ENERGY VENTURI SODIUM-BASED SCRUBBING SYSTEMS APPLIED TO FLUID CATALYTIC CRACKING UNITS[a,b]

	2500 m^3/sd (15,725 bbl/sd) Model Unit		8000 m^3/sd (50,320 bbl/sd) Model Unit	
	1.5 (wt.%) Sulfur Feed Content	3.5 (wt.%) sulfur Feed Content	1.5 (wt.%) Sulfur Feed Content	3.5 (wt.%) Sulfur Feed Content
Direct Operating Cost	52.4	52.4	52.4	52.4
Maintenance	91.5	91.5	160.5	160.5
Electricity	21.9	21.9	70.0	70.0
Water	10.0	10.0	29.9	29.9
Compressed Air	0.4	0.4	0.4	0.4
Caustic Soda (Soda Ash)	569.7 (349.2)	1065.6 (653.2)	1823.6 (1117.9)	3397.0 (2082.4)
Steam	1.1	1.1	3.1	3.1
Polyelectrolyte	4.8	4.8	14.3	14.3
Waste Disposal	6.9	6.9	22.2	22.2
Indirect Operating Costs	244.0	244.0	428.0	428.0
Capital Recovery Cost	815.0	815.0	1385.6	1385.6
Total Annual Cost with Caustic Soda (Soda Ash)	1817.7 (1597.2)	2313.6 (1901.2)	3990.0 (3284.3)	5563.4 (4248.8)

[a] Costs in thousands of dollars; adjusted to 1st quarter, 1985. Reference 16.

[b] Based on 90 percent SO_x control.

TABLE 5.3-5. ANNUAL COSTS FOR JET EJECTOR VENTURI SODIUM-BASED SCRUBBING SYSTEMS[a,b]

	15,725 (bbl/sd) Model Unit	50,320 (bbl/sd) Model Unit
Direct Operating Cost	52.4	52.4
Maintenance	126.0	222.0
Electricity	280.1	898.7
Water	10.0	29.9
Compressed Air	0.4	0.4
Caustic Soda (Soda Ash)	454.1 (278.9)	1454.2 (899.9)
Steam	1.1	3.1
Polyelectrolyte	4.8	14.3
Waste Disposal	6.9	22.2
Indirect Operating Costs	336.0	592.0
Total Recovery Cost with Caustic Soda (Soda Ash)	2392.5 (2217.3)	5245.3 (4691.0)

[a] Costs in thousands of dollars; adjusted to 1st quarter, 1985. Reference 16.

[b] Based on feed stream sulfur content of 1.5 wt. percent and 90 percent SO_x control.

TABLE 5.3-6. COST EFFECTIVENESS OF SODIUM-BASED SCRUBBING SYSTEMS

Model Unit Fresh Feed Capacity (bbl/sd)	Feed Stream Sulfur Content (wt.%)	Scrubber Type	Total Annual Cost[a] with Caustic Soda (Soda Ash)	Reduction in[b] SO_x Emissions (tons/year)	Reduction in[c] $SO_4^=$ Emissions (tons/year)	Cost Effectiveness (\$/ton $SO_4^=$ removed)
15,725	1.5	High Energy Venturi	1818 (1597)	1840	21.4	84,950 (74,630)
		Jet Ejector Venturi	2392 (2217)	1840	21.4	111,780 (103,600)
	3.5	High Energy Venturi	2314 (1901)	3440	40.2	57,560 (47,290)
50,320	1.5	High Energy Venturi	3900 (3284)	5885	68.7	56,770 (47,800)
		Jet Ejector Venturi	5245 (4691)	5885	68.7	76,350 (68,280)
	3.5	High Energy Venturi	5563 (4245)	10,990	128.2	43,390 (33,110)

[a] Costs in thousands of dollars, adjusted to first quarter 1985.

[b] Based on 90 percent SO_x control.

[c] Based on a factor of 0.03 (tons acid sulfates/ton SO_x) derived from References 16 and 17 and 35 percent sulfate removal efficiency.

TABLE 5.3-7. COST EFFECTIVENESS OF SULFATE REMOVAL BY SODIUM-BASED SCRUBBING SYSTEMS APPLIED TO FLUID CATALYTIC CRACKING UNITS

Model Unit Fresh Feed Capacity m^3/sd (bbl/sd)	Feed Stream Sulfur Content (wt. %)	Scrubber Type	Total Annual Cost[a] with Caustic Soda [Soda Ash]	Reduction in[b] Sulfate Emissions Mg/yr (tons/yr)	Cost Effectiveness $/Mg ($/ton Sulfate Removed)
2500 (15,725)	1.5	High Evergy Venturi	1818 [1597]	19.4 (21.4)	93,640 (84,950) [82,270] (74,630)
		Jet Ejector Venturi	2392 [2217]	19.4 (21.4)	123,220 (111,780) [114,200 (103,600)]
	3.5	High Energy Venturi	2341 [1901]	36.5 (40.2)	63,450 (57,560) [52,130 (47,290)]
8000 (50,320)	1.5	High Energy Venturi	3900 [3284]	62.3 (68.7)	62,580 (56,770) [52,690 (47,800)
		Jet Ejector Venturi	5245 [4691]	62.3 (68.7)	84,160 (76,350) [75,270 (68,280)
	3.5	High Energy Venturi	5563 [4245]	116.3 (128.2)	47,830 (43,390) [36,500 (33,110)]

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[a] Costs in thousands of dollars, adjusted to first quarter 1985.

[b] Based on a factor of 0.03 (Mg acid sulfates/Mg SO_x) delivered from Reference 16 and 18 and 35 percent sulfate removal efficiency.

TABLE 5.4-1 COSTS FOR ACID PLANTS EMPLOYED ON MODEL COPPER SMELTER[a]

	Single-Stage Acid Plant	Dual-Stage Acid Plant
Capital Costs		
Capital[b]	37,400	42,800
Retrofit Cost[c]	11,300	12,800
Total Capital Investment	48,700	55,600
Annual Costs		
Operating Labor	328	328
Maintenance	2,244	2,568
Electricity	878	1,048
Process Water	546	546
Total Direct Costs	3,996	4,490
Indirect Costs[d]	3,996	2,224
Total Direct and Indirect Costs	5,944	6,714
Capital Recovery Cost[e]	6,400	7,300
Total Annual Cost	12,344	14,014

[a] Costs in thousands of dollars (March 1985). Reference 19.
[b] Battery limits costs, including site clearance and hook-up of available off-site facilities. Reference 19.
[c] Assumed to be 30 percent of capital.
[d] Assumed to be 4 percent of total capital investment.
[e] Based on 10 percent interest rate and 15 year plant life. Capital recovery factor equals 0.1315.

TABLE 5.4-2. COST-EFFECTIVENESS DATA FOR ACID PLANTS[a]

Plant Type[b]	Total Annual Cost ($1000)	Sulfate Emissions[c,d] Reduction Mg/yr (tons/yr)	Cost-Effectiveness $/Mg ($/ton) (Sulfate Removed)
SCSA	12,344	1,260 (1,390)	9,800 (8,900)
DCDA	14,014	1,320 (1,450)	10,600 (9,700)

[a] Costs in March 1985 dollars.

[b] SCSA = Single contact, single absorption acid plant;
DCDA = Double contact, double absorption acid plant

[c] Based on 96 percent SO_2 control efficiency for SCSA plants and 99.7 percent control efficiency for DCDA plants. Reference 18.

[d] Total emission based on SO_2 emissions data from Reference 18.

TABLE 5.4-3. COST-EFFECTIVENESS DATA FOR ACID PLANTS - SO_2[a]

Plant Type[b]	Total Annual Cost ($1000)	SO_2 Emissions[c,d] Reduction Mg/yr (tons/yr)	Cost-Effectiveness $/Mg ($/ton) (SO_2 Removed)
SCSA	12,344	93,300 (10,300)	130 (120)
DCDA	14,014	97,800 (107,400)	140 (130)

[a] Costs in March 1985 dollars.

[b] SCSA = Single contact, single absorption acid plant;
DCDA = Double contact, double absorption acid plant

[c] Based on 96 percent SO_2 control efficiency for SCSA plants and 99.7 percent control efficiency for DCDA plants. Reference 18.

[d] Total emission based on SO_2 emissions data from Reference 18.

$1,070/Mg ($9,700/ton) sulfate removed. The incremental cost-effectiveness is $30,900 per additional Mg ($28,000 per additional ton) of sulfate removed by the DCDA plant over the SCSA plant. All costs were taken from Reference 19 and updated to March 1985 dollars using CE plant cost indices.

5.5 COKE OVENS

All costs presented in this section are those associated with the vacuum carbonate desulfurization system discussed in Section 4.5. This process removes H_2S from coke oven off-gas before it is recycled to the oven battery as combustion fuel for underfiring. Single-stage vacuum carbonate systems achieve H_2S removal efficiencies of 80 to 93 percent, while two-stage systems reach efficiencies of 98 percent.[20] The amount of sulfur available for SO_x production during combustion is proportionally reduced. Mass balances reported in Reference 20, based on 90 percent H_2S removal, indicate that SO_2 emissions are reduced by about 82 percent. For the purpose of this analysis, vacuum carbonate systems are also assumed to reduce sulfate emissions by 82 percent.

The assumptions and bases used to derive costs for the model plants are presented in Table 5.5-1. Capital costs, presented in Table 5.5-2, were taken from Reference 21 and updated to March 1985 dollars using CE plant cost indices. A retrofit cost equalling 30 percent of the total capital investment (TCI) required for a new unit was applied to obtain the retrofit TCI. Annual costs were derived from information in References 15 and 20. Credit was given for sulfur produced by the Claus sulfur recovery unit incorporated into the desulfurization plant. The net annual cost, therefore, is the difference between total annual cost and sulfur credit. It should also be noted that steam is both generated and consumed by the total process. The annual steam cost is a net charge for the difference between steam generation and consumption. Annual costs are listed in Table 5.5-3.

Cost-effectiveness data are presented in Table 5.5-4 and 5.5-5. The cost-effectiveness of retrofitting vacuum carbonate systems on 2,000 and 6,000 Mg/day (2,200 and 6,600 tons/day) coke plants are $11,700 and $7,000 ($10,600 and $6,300) per ton of sulfate removal, respectively.

TABLE 5.5-1. BASES AND ASSUMPTIONS FOR VACUUM CARBONATE COSTS[a]

1. Coke ovens operate on a 17 hour cycle, 365 days per year.
2. Operating labor assumed as 6205 hrs/yr at $15.70 per hour. Supervision assumed as 1/4 of time required for operating labor at $17.04 per hour.
3. Maintenance and repair taken as 3 percent of total capital investment (TCI).
4. Indirect annual costs include taxes, insurance, and administration and equal 4 percent of TCI.
5. Capital costs updated to March 1985 dollars using CE Plant Cost indices. Annual costs updated to March 1985 dollars using BLS producer price indices where applicable.
6. Unit cost assumptions:

Item	Cost[a]
Steam	$5.75/1000 lbs
Soda Ash[b]	$120/ton
Power	$ .05/KWH
Cooling Water	$ .05/1000 gal

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[a] Assumptions derived from References 15 and 20.
[b] Chemical Market Reporter, March 11, 1985.

TABLE 5.5-2. CAPITAL COSTS FOR A VACUUM CARBONATE SYSTEM APPLIED TO MODEL COKE OVENS[a]

	2000 Mg/D (2200 TPD)[b,c]	6000 Mg/D (6600 TPD)[b,c]
Desulfurization	2.71	5.03
Claus Sulfur Recovery	1.04	1.43
Total Capital Investment (New Coke Plant)	3.75	6.46
Retrofit Cost[d]	1.12	1.94
Total Capital Investment (Existing Coke Plant)	4.87	8.40

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[a] Installed costs in millions of dollars taken from Reference 20 and updated to March 1985 dollars.

[b] TPD = tons of coal charged per day.

[c] 2000 and 6000 Mg/D (2200 and 6600 TPD) correspond to 20 million and 60 million SCFD, respectively. Inlet gas concentration based on 500 grains H_2S/100 SCF. Reference 20.

[d] Retrofit cost assumed to be 30 percent of total capital investment (new plant).

TABLE 5.5-3. ANNUAL COSTS FOR A VACUUM CARBONATE SYSTEMS APPLIED TO MODEL COKE OVENS (RETROFIT)[a]

	2000 Mg/D (2200 TPD)	6000 Mg/D (6600 TPD)
Labor	171,000	171,000
Maintenance and Repair	146,000	252,000
Steam	232,600	789,200
Power	33,500	99,300
Cooling Water	21,600	64,800
Soda Ash	6,700	20,000
Indirect Annual Costs	195,000	336,000
Total Operating & Maintenance	764,000	1,732,000
Capital Cost	640,000	1,105,000
Total Annual Cost	1,404,000	2,837,000
Sulfur Credit	258,000	774,000
Net Annual Cost	1,146,000	2,063,000

[a] All costs in dollars per year (March 1985) calculated using data from Reference 20 and assumptions in Table 5.5-1.

TABLE 5.5-4. COST-EFFECTIVENESS DATA FOR VACUUM CARBONATE SYSTEMS APPLIED TO MODEL COKE OVENS - SULFATE

Parent Coke Plant Size	Net Annual Cost ($/yr)	Sulfate Emissions Reduction Mg/yr (tons/yr)	Cost-Effectiveness $/Mg ($/ton) (Sulfate removed)
New			
2200	963,000	98.3 (108.4)	9,800 (8,900)
6600	1,672,000	295.0 (325.2)	5,600 (5,100)
Retrofit			
2200	1,146,000	98.3 (108.4)	11,700 (10,600)
6600	2,063,000	295.0 (325.2)	6,900 (6,300)

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[a] Based on SO_2 mass balance data for model in Reference 20 and WG3B acid sulfate emissions factor.

TABLE 5.5-5. COST-EFFECTIVENESS DATA FOR VACUUM CARBONATE SYSTEMS APPLIED TO MODEL COKE OVENS - SO_2

Parent Coke Plant Size	Net Annual Cost ($/yr)	SO_2 Emissions Reduction Mg/yr (tons/yr)	Cost-Effectiveness $/Mg ($/ton) (SO_2 removed)
New			
2200	963,000	1,200 (1,320)	800 (730)
6600	1,672,000	3,600 (3,970)	460 (420)
Retrofit			
2200	1,146,000	1,200 (1,320)	955 (870)
6600	2,063,000	3,600 (3,970)	570 (520)

[a] Based on SO_2 mass balance data for model in Reference 19 and W63B acid sulfate emissions factor.

5.6 PRIMARY ALUMINUM

In Section 4.6 it was estimated that total emissions of HF from domestic primary aluminum smelters could be reduced from 5,900 to 1,400 Mg (6,500 to 1,500 tons) per year by applying the best demonstrated controls. These controls consist of effective hooding systems (which minimize secondary emissions) in combination with wet or dry scrubbing of primary gases.[21] Section 4.6 also mentioned the great variability of plant type and configuration existing among primary aluminum smelters in the U. S. Since this makes control applications site specific, model plants could not be developed.

Tables 5.6-1 and 5.6-2 present control modules taken from Reference 21, which are used in cost analysis. The modules represent options for upgrading existing primary smelters, including removal of inadequate control equipment and installation of the best demonstrated controls. Costs were updated to March 1985 dollars using CE plant cost indices.

To determine capital and annual costs for a specific smelter, control modules should be selected to make a complete retrofit scenario. Module costs are then summed to give a total retrofit cost. An example retrofit case for smelters using each reduction cell type is presented in Table 5.6-3. The cost-effectiveness results are determined on the cumulative costs obtained by adding the annual costs of selected control modules and on the corresponding incremental decrease in fluoride emissions. For the center-worked prebake cell, anode bake plant controls (Module 8-I) was selected as the baseline control at annual costs of $10.15/Mg Al produced and fluoride emissions of 6.2 kg/Mg Al. When control is increased by:

- Installing a fluidized bed dry scrubber, primary (Module 7-I),
- Removing a dry ESP (Module 1-R),
- Removing a spray tower - primary (Module 6-R), and
- Installing a spray screen - secondary (6-I);

the cumulative annual cost increases to $67.04/Mg Al produced to achieve an incremental reduction in emissions of 3.9 kg/Mg Al (6.2 kg F^-/Mg Al -

TABLE 5.6-1. CONTROL MODULES FOR INSTALLING BEST AVAILABLE CONTROL TECHNOLOGY FOR PRIMARY ALUMINUM SMELTERS

Control Module[a]	Capital Cost[b]	Annual Cost[b]
VSS		
1-I. Install spray screen-secondary	166.94 (151.45)	55.62 (50.46)
CWPB AND SWPB		
2-I. Lime treatment of cryolite bleed stream	4.17 (3.78)	1.83 (1.66)
3-I. Improve hooding	31.79 (28.84)	8.13 (7.38)
4-I. Install primary collection system	72.93 (66.16)	20.24 (18.40)
5-I. Install injected alumina dry scrubber - primary	112.93 (102.45)	-3.09 (-2.80)
6-I. Install spray screen - secondary	119.24 (108.17)	39.98 (36.35)
7-I. Install fluidized bed dry scrubber - primary	129.55 (117.53)	5.54 (5.03)
8-I. Install anode bake plant controls	34.39 (31.20)	10.15 (9.21)
HSS		
9-I. Lime treatment of cryolite bleed stream	4.17 (3.78)	1.83 (1.66)
10-I. Improve hooding	31.79 (28.84)	8.13 (7.38)
11-I. Install spray screen - secondary	166.94 (151.45)	55.61 (50.45)

---

[a] VSS = vertical-stud Soderberg cell, CWPB = center-worked prebake cell, SWPB = side-worked prebake cell, HSS = horizontal-stud Soderberg cell.

[b] Costs in $/Mg ($/ton) annual capacity updated to March 1985 dollars. Reference 21.

[c] Credit.

TABLE 5.6-2. CONTROL MODULES FOR REMOVAL OF INADEQUATE, EXISTING CONTROL EQUIPMENT FOR PRIMARY ALUMINUM SMELTERS

Control Module	Capital Cost[a] $/Mg ($/ton)	Annual Cost[a,b] $/Mg ($/ton)
CWAB AND SWPB		
1-R. Removal dry ESP - primary	13.7 (11.95)	2.97 (2.69)
2-R. Removal floating bed wet scrubber - primary	12.84 (11.65)	-13.93(-12.64)
3-R. Remove coated bag filters - primary	24.11 (21.87)	2.00 (1.81)
4-R. Remove fluidized bed dry scrubber - primary	34.39 (31.20)	-5.54 (-5.03)
5-R. Remove multiple cyclone - secondary	14.04 (12.74)	-10.14(-9.20)
6-R. Remove spray tower - primary	5.95 (5.40)	-7.23 (-6.56)
HSS		
7-R. Remove spray tower - primary	10.46 (9.49)	-11.36(-10.31)
8-R. Remove floating bed scrubber - primary	128.89(116.93)	136.45(123.74)

[a] Costs in $/Mg annual capacity ($/ton annual capacity), taken from Reference 21 and updated to March 1985 dollars.

[b] Negative numbers indicate a credit given for the module.

TABLE 5.6-3. EXAMPLE RETROFIT CONTROL COST SCENARIOS FOR PRIMARY ALUMINUM SMELTERS

Cell Type Plant Code[f]	Control Module[g]	Capital Cost[a] \$/Mg (\$/ton)	Annual Cost[a] \$/Mg (\$/ton)	Average F^- Emissions kg F^-/Mg Al (lb F^-/ton Al)	Cumulative Cost-Effectiveness \$/Mg F^- Removed (\$/ton F^- Removed)
VSS/5A[b]		---	---	2.1 (4.2)	---
	11-I	166.94 (151.45)	55.61 (50.45)	0.6 (1.2)	37,080 (33,640)
CWPB/4A[c]	8-I	34.39 (31.20)	10.15 (9.21)	6.2 (12.5)	---
	7-I, 1-R, 6R	182.69 (166.08)	11.43 (10.37)	2.3 (4.7)	2,930 (2,660)
	6-I	301.67 (274.25)	67.04 (60.82)	0.9 (1.9)	12,650 (11,480
SWPB/24[d]	8-I	34.39 (31.20)	10.15 (9.21)	24.0 (48.0)	---
	4-I, 5-I	220.25 (199.81)	27.30 (24.81)	5.1 (10.2)	1,430 (1,300)
	6-I	339.49 (307.98)	67.28 (61.16)	1.5 (3.0)	2,980 (2,700)
HSS/26[e]	9-I	4.17 (3.78)	1.83 (1.66)	17.2 (34.5)	---
	10-I	35.96 (32.62)	9.96 (9.04)	9.2 (18.4)	1,230 (1,120)
	11-I	202.90 (184.07)	65.58 (59.49)	3.7 (7.4)	4,850 (4,400)

[a] Costs in \$/Mg annual capacity (\$/ton annual capacity) updated to March 1985 dollars. Reference 21.

[b] Presently operating with best primary control.

[c] Baseline controls consist of a dry ESP and a spray tower.

[d] No primary or secondary baseline control.

[e] Spray tower is the only baseline control.

[f] VSS = vertical-stack Soderberg cell, CWPB = center-worked prebake cell, SWPB = side-worked prebake cell, HSS = horizontal-stud Soderberg cell.

[g] For control module description, see Tables 5.6-1 and 5.6-2.

0.9 kg F^-/Mg Al). The cost effectiveness for this scenario is \$12,650/Mg F^-. To determine the cost-effectiveness of adding Module 6-R to already installed Modules 7-I, 1-R, and 6-R incremental cost increase (\$67.04/Mg Al - \$11.43/Mg Al) is used and the incremental emissions reduction (2.3 kg F^-/Mg Al - 0.9 kg F^-/Mg Al) is used. The result is \$39,680/Mg F^-. Plant codes are given as listed in Reference 21. Cost effectiveness data is valid only for each specific plant shown and is not representative of the industry as a whole. In addition, a national retrofit cost can not be calculated unless present control equipment inventories for all existing primary aluminum smelters are available.

5.7 MUNICIPAL SOLID WASTE INCINERATORS

This section presents the costs associated with retrofitting caustic soda (NaOH)- based wet scrubbers to the model municipal solid waste (MSW) incinerators developed in Section 4.7. The assumptions and bases used to derive these costs are listed in Table 5.7-1.

It should be noted that scrubber costs are based on stainless steel construction material. In reality, stainless steel units could experience corrosion problems due to high chloride concentrations in incinerator flue gas. Alternative materials can be applied when this occurs. Wet scrubbers employed on utility boilers which operate in high chloride environments are often constructed of organic-lined or glass flake/polyester-lined carbon steel.[23] Costs for these materials, however, are less than those for stainless steel. Thus, the costs presented in this section should be conservative.

Caustic soda requirements take into account reagent utilization for SO_2 absorption, as well as HCl control. Ninety percent removal of both compounds is assumed.[8] Cost-effectiveness is given in terms of HCl removal only, since it is the acidic material of concern for the purpose of this study.

Results of the cost analysis are presented in Table 5.7-2. Cost-effectiveness for scrubbing HCl from the flue gas of the 381 Mg/day (420 tons/day) MSW incinerator is \$1,903/Mg (\$1,726/ton) HCl removed. The scrubber on the 726 Mg/day (800 tons/day) unit requires \$1,481/Mg (\$1,344/ton) HCl removed.

TABLE 5.7-1. ASSUMPTIONS AND BASES USED IN COST ANALYSIS FOR SODIUM-BASED SCRUBBERS APPLIED TO MODEL MSW INCINERATORS

1. A retrofit factor of 1.3 was applied to capital costs.
2. Caustic soda requirements were obtained via SO_2 and HCL emissions factors and stoichiometric mass balances.
3. Capital costs for material handling systems are based on information in Reference 22.
4. Scrubber costs are based on algorithms and cost data from References 1 and 23.
5. Capital recovery charges are based on a 15 year equipment life and 10 percent interest rate.
6. Capital costs and annual costs were updated to March 1985 dollars using CE plant cost indices and BLS producer price indices, respectively.
7. The price for caustic soda (50% NaOH) is \$176/Mg (\$160/ton). 1983 dollars, Reference 22.
8. The absorber is the spray baffle type.
9. The scrubber construction material is 316 stainless steel.

TABLE 5.7-2. COST RESULTS FOR SODIUM-BASED SCRUBBERS ON MODEL MSW INCINERATORS

Incinerator Capacity	726 Mg/D (800 TPD)	381 Mg/D (420 TPD)
Total Capital Investment ($)	1,161,400	826,300
Total Operating & Maintenance ($/yr)	576,400	315,900
Total Annual Cost ($/yr)	760,700	448,700
HCL Emissions Reduction* (tons/yr)	514 (566)	236 (260)
SO_2 Emissions Reduction Mg/yr (ton/yr)	271 (299)	127 (140)
Cost-Effectiveness $/Mg ($/ton) (SO_2 removed)	2,800 (2,540)	3,530 (3,200)
Cost-Effectiveness ($/ton HCL removed)	1,482 (1,344)	1,903 (1,726)

---

*Based on emission factor (Reference 12) and 90 percent HCL removal efficiency.

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6.0 RESEARCH AND DEVELOPMENT

With the focus on developing control technologies for removal of high volume pollutants (SO_2, NO_x, PM), little research and development (R & D) activity was uncovered in the acidic materials control area. Granular bed filters have been tested for SO_3 and acid mist control on a primary copper smelter (Section 6.3). Otherwise, acidic materials control can probably benefit from work being done to improve existing controls or to develop new technologies for control of the aforementioned high volume pollutants.

Recent development work in particulate collection include potential improvements in costs and performance of electrostatic precipitators (ESP) and fabric filters (Section 6.1), including better acid mist controls on wet scrubbing systems. Electron-beam irradiation is a SO_x/NO_x control process in early stages of development that converts SO_2 and NO_x to sulfuric acid and nitric acid (Section 6.2) and ultimately to ammonium or calcium salts. Successful acidic materials control will depend on particulate control performance for removal of these salts as well as reaction kinetics for the ensuing reactions. This further highlights the need for developing improved particulate controls.

6.1 RESEARCH AND DEVELOPMENT IN PARTICULATE CONTROL

Several technologies available for the control of acidic materials involve the injection of sorbents into flue gas followed by particulate collection in a fabric filter or an electrostatic precipitator. Examples of these technologies include lime spray drying and sodium dry injection for coal-fired boilers and alumina dry injection for primary aluminum smelters.

Application of sorbent injection technologies may result in the need for 1) modification of existing particulate control equipment or 2) installation of new equipment to meet particulate emission requirements. The choice between modifying existing equipment (if present) and installing new equipment will generally be based on economics. However, another consideration is the effect that this choice may have on the acidic material removal capability of the sorbent injection technology. Many of the injection technologies rely on the intimate flue gas/sorbent contacting that occurs on the surface of fabric filters to achieve effective acidic materials control.

Recent R & D activities in the area of particulate control offer potential improvements in 1) the costs and particulate removal performance of ESP's and 2) the costs of fabric filters. These R & D activities are summarized briefly in the following sections. Discussions in the following sections are based on readily available information.

6.1.1 Electrostatic Precipitators

Recent ESP research is largely directed toward the improvement of removal performance with high resistivity dusts. Results of this work will also be applicable to situations where improved ESP performance is needed to allow acidic materials control. Areas of on-going research involve the use of large diameter electrodes and particle precharging techniques.

Pilot- and laboratory-scale studies conducted under EPA funding have shown that the use of large diameter, smooth-surface electrodes can provide a significant improvement in ESP performance, especially when high resistivity dust is collected. Recent test results indicate that large diameter wires can reduce the penetration of the ESP for high resistivity dust ($> 2 \times 10^{12}$ ohm-cm) by a factor of 4 and the penetration for moderate resistivity dust (8×10^{10} ohm-cm) by a factor of 1.25.[1] Performance of the ESP is improved because the large diameter electrodes allow operation at high field strengths and useful current densities. Cost analyses indicate that the large diameter wire technology should be economical for dust resistivities greater than about 8×10^{10} ohm-cm.

One promising precharger technique currently under investigation is the cold-pipe precharger. The cold-pipe precharger, shown in Figure 6-1, consists of discharge wires interspersed with grounded pipes through which cooling water flows. The purpose of the cooling water is to cool the dust

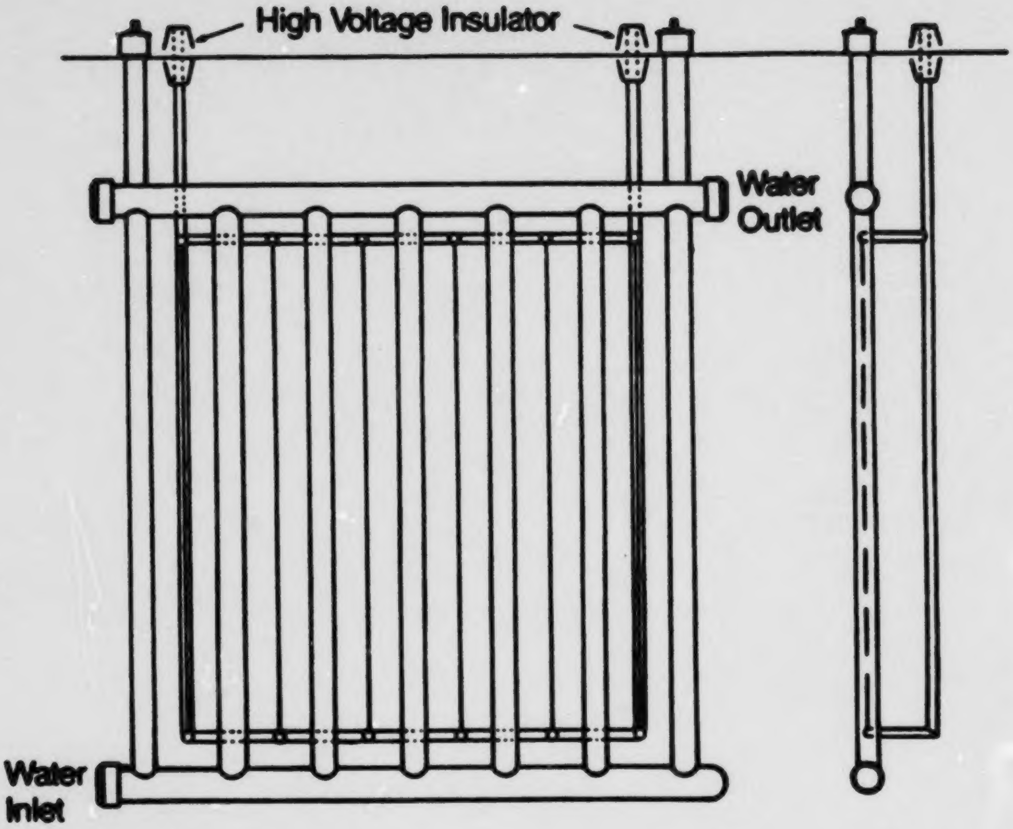
High Voltage Insulator
Water Outlet
Water Inlet

Figure 6-1. Cold-pipe precharger.

layer that forms on the pipes and thus lower the dust resistivity. Based on EPA pilot tests (28 actual m^3/min) with high resistivity dusts, the use of cold-pipe precharging in combination with large diameter electrodes can reduce the collection plate area required for a given collection efficiency to 20 or 25 percent of that needed for a conventional ESP.

6.1.2 Fabric Filtration

Recent R & D activities in the fabric filtration area involve electrostatically augmented fabric filtration (ESFF). The ESFF technology uses an electric field parallel to the fabric surface to reduce the flow resistance of the collected dust. This reduced resistance results in lower fabric filter pressure drops and thus may allow operation at increased operating face velocities.

For pulse-jet FSFF operation, the electric field is generated using a special filter bag cage in which alternate cage rods are electrically connected. A typical cage-type electrode is illustrated in Figure 6-2. Electrodes for reverse-air units consist of filter bags with stainless steel yarns, each containing 90 filaments, woven into the fabric.

Changes in the pattern of dust deposition on the filter that may account for the reduced pressure drop include:[2]

- an increased fraction of dust collecting on or near the upstream surface of the filter (instead of penetrating deep within the filter),
- changes in the pattern of particle collection, such as more dendritic collection and bridging, and
- formation of a highly non-uniform dust deposit on the filter surface.

Pilot-scale testing of ESFF on both pulse-jet and reverse-air cleaned baghouses has shown about a 50 percent reduction in pressure drop when compared to a conventional baghouse. These tests were conducted on a 7.1 actual m^3/hr (15,000 acfm) pilot unit treating flue gas from an industrial coal-fired boiler. The pilot unit consisted of two baghouses, one ESFF unit

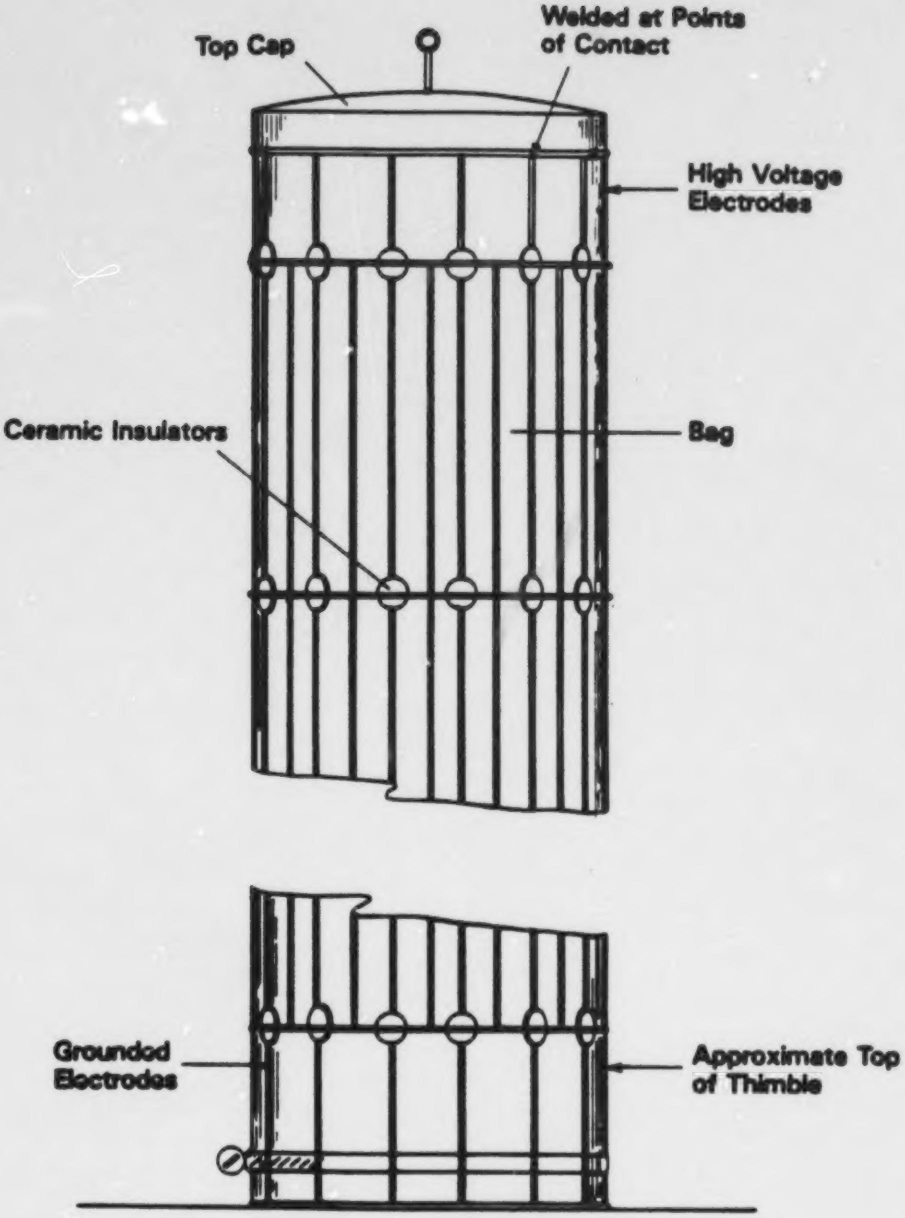
Top Cap
Welded at Points of Contact
High Voltage Electrodes
Ceramic Insulators
Bag
Grounded Electrodes
Approximate Top of Thimble

Figure 6-2. Reverse-air "RIGID" cage.

and one conventional unit, operated in a parallel arrangement. During the testing, no significant reduction in particulate removal performance was observed for ESFF operation.

Economic analyses indicate that the power savings associated with the reduced pressure drop of ESFF do not justify installation on existing baghouses or on new baghouses that will operate at conventional face velocities (i.e., the velocity through the bag). However, operation of an ESFF baghouse at an increased face velocity appears to be an attractive alternative and the pilot data indicate that such operation, may be possible.

For new units, an ESFF reverse-air system operated at 2 cm/s (4 ft/min) using bags costing 3 times conventional bags would have an 11-percent economic advantage over a conventional system at 1 cm/sec (2 ft/min). Similarly, an ESFF pulse-jet system would have a 30-percent advantage at 3 cm/s (6 ft/min) compared to a conventional system at 2 cm/s (4 ft/min).

Costs for ESFF appear to be most sensitive to face velocity with bag costs also being an important factor.

6.1.3 Impact of Particulate R&D on Acidic Materials

Research and development in the area of particulate matter control will affect the control of acidic emissions by enhancing particulate control performance. As discussed in the previous sections, improved particulate removal can be achieved by modification of existing ESPs with large diameter electrodes and particle precharging techniques. This type of modification would reduce the emissions of sulfates under the following two retrofit scenarios:

1) Upgrading the performance of an existing ESP, and

2) Upgrading the performance of an existing ESP in combination with a sorbent injection technology which would reduce sulfate emissions by neutralizing SO_2 and acid sulfates with the sorbent.

Additionally, improved acidic material removal would be achieved by modifying an existing fabric filter system combined with sorbent injection such that the sorbent could be injected without increasing the system pressure drop.

Improved particulate control after wet scrubbing would also reduce emissions of acid mist. Currently, almost all wet scrubbing systems control aerosol emissions from the absorber with mist eliminators. However, if a high-efficiency ESP was placed downstream of the scrubber, instead of a conventional mist eliminator, acid sulfate removal would improve.

In fact, a petroleum coke-fired cogeneration plant now under construction, with a heat input of approximately 15,230 GJ/hr (15,000 million Btu/hr), will use a wet ESP for SO_3 and acid mist control following a wet limestone scrubber.[3] Wet ESPs use water to wash material away from the collection plates rather than rapping, which is used by dry ESPs.

6.2 ELECTRON-BEAM IRRADIATION

An area of non-particulate R&D which could affect acidic material control is electron-beam (E-beam) irradiation. E-beam processes involve the irradiation of flue gas containing a reactant, such as ammonia or lime. The process removes both SO_2 and NO_x from the flue gas and produces a dry waste product that must be subsequently removed in a particulate collector.

A schematic diagram of the E-beam/ammonia process is shown in Figure 6-3. In this process, incoming flue gas is cooled and humidified in a water quench tower, resulting in a gas moisture content of about 10 percent. Ammonia is injected into the cooled gas and the gas is passed through an E-beam reactor. In the reactor, oxygen and water are ionized to form the radicals [HO], [O], and $[HO_2]$ by the application of electrons at a dose of 1 to 3 Mrads (1 Mrad is equivalent to 10 joules/g of flue gas). These radicals react with SO_2 and NO_x to form sulfuric acid (H_2SO_4) and nitric acid (HNO_3). The acids are neutralized by ammonia and water in the flue gas to form solid ammonium sulfate ($(NH_4)_2SO_4$) and ammonium sulfate nitrate ($(NH_4)_2SO_4$ 2 NH_4NO_3). The reaction time for formation of the

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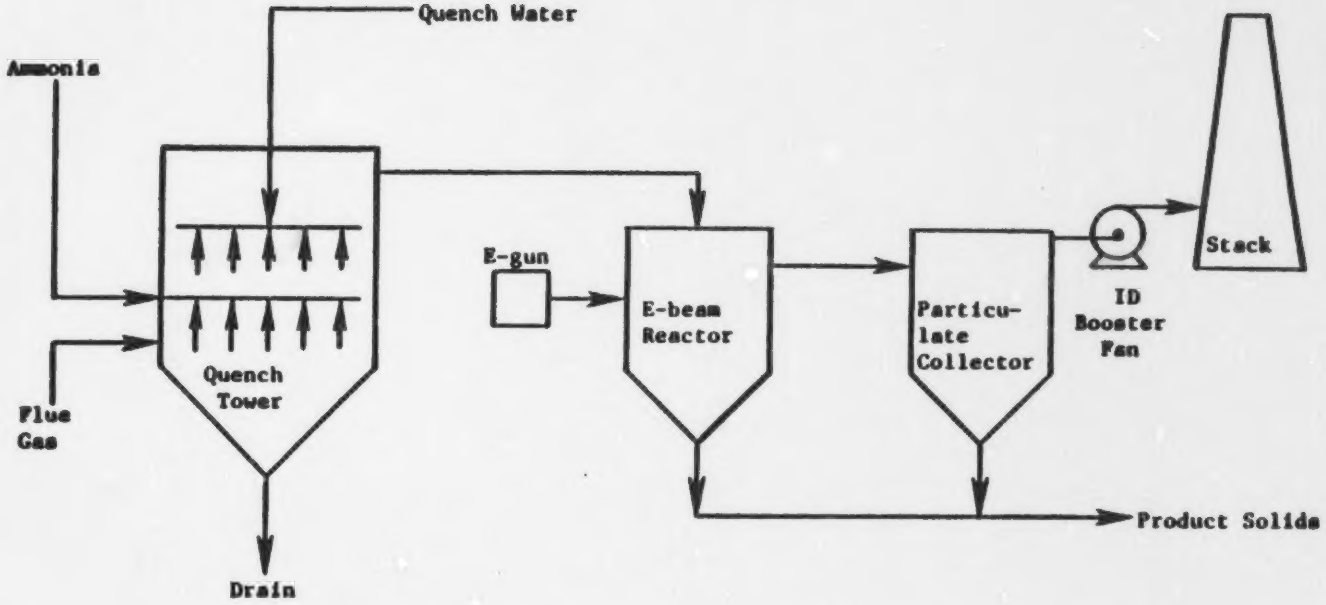
Quench Water
Ammonia
Flue Gas
Quench Tower
Drain
E-gun
E-beam Reactor
Particu-late Collector
ID Booster Fan
Stack
Product Solids

Figure 6-3. E-beam/ammonia process flow diagram.

sulfate and nitrate salts is less than one second. Product solids are collected in a hopper below the E-beam reactor or in a downstream particulate collector.

In another version of the E-beam process, the water quench tower is replaced with a lime-based spray dryer (see Section 2.2.1). Reactions in the E-beam reactor occur in the same manner as above except that the products formed are calcium salts ($CaSO_4$, $Ca(NO_3)_2$, and $CaSO_3$) instead of ammonium salts.[4]

6.3 GRANULAR BED FILTER

A system which has been tested for SO_3 and acid mist control on a primary copper smelter is the sorbent injection/granular bed filter process.[5] This process uses an electrostatically charged sorbent in combination with moving granular bed filters for dual acid gas/particulate control. A dry sorbent (e.g., hydrated lime, soda ash) is electrostatically charged and injected into the hot flue gas. The gas stream then enters a collection chamber where it passes through a series of moving granular bed filters. The particulate matter and reaction products are collected in the filters. As the granular bed of each filter moves through the chamber and is discharged, the filter media are screened to remove collected material.

Table 6-1 presents the results of a pilot test conducted at a primary copper smelter's reverberatory furnace. The off-gas first passed through an ESP operated to achieve 95 percent particulate removal and then through the sorbent/filter system.

TABLE 6-1. EMISSIONS TEST DATA FOR A GRANULAR BED FILTER APPLIED TO A COPPER SMELTER[a,b]

	Inlet g/m^3 (gr/dscf)	Outlet g/m^3 (gr/dscf)	Removal %
	0.5991 (0.2618)	0.0098 (0.0043)	98.3
	0.2883 (0.1260)	0.0178 (0.0078)	93.8
	0.4661 (0.2037)	0.1638 (0.0716)	64.8
Average	0.4513 (0.1972)	0.0638 (0.0279)	85.6

[a] Emissions data given in terms of SO_3/H_2SO_4 mist.
[b] Source: Reference 5.

6.4 REFERENCES

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APPENDIX A

DERIVATION OF ACIDIC EMISSIONS ESTIMATES

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APPENDIX A - ACIDIC EMISSIONS ESTIMATES

A literature search was done to identify domestic combustion and industrial sources of acidic emissions. Based on the information found for each source category, emissions estimates were made. Generally, this was accomplished via emission factors and national process capacities found in the literature.

This section presents the estimates for each category and the methods by which they were derived. The acidic materials discussed are sulfates, HCl, HF, and nitrates. Section A.1 discusses sulfate emission sources. Sections A.2 and A.3 cover sources of HCl and HF emissions, respectively. Sources of nitrate emissions are discussed in Section A.4.

Emissions are discussed in terms of national emissions and local emissions. National emissions refer to the total emissions of a given substance in the U.S. by a specific combustion or industrial source. Local emissions deal with the possibility of high emission levels in a specified area of the U.S. This could result when a large plant or a concentration of plants, representing a single source category, exists in the area of concern.

A.1 SULFATE EMISSION SOURCES

This section contains an analysis of available information on sulfate emissions from industrial sources and electric utilities. The approach used was to use the best existing data; no new information was generated.

The work that Working Group 3B (WG3B) did on estimating sulfate emissions was used as a starting point (Reference 1). That information was augmented with Background Information Documents for air standards, U.S. Mineral Industry Surveys, and other references. National Emissions Data System (NEDS) data were used in some cases. These data were used only as a last resort, however, because obvious frequent omissions were evident.

The overall results of the study of sulfate emissions are shown in Table A1. As the table shows, highest national emissions were estimated for utility boilers, industrial boilers, Kraft pulp mills, and cement plants. Possible high local sulfate ambient air concentrations were indicated for coke plants, primary copper smelters, and Claus plants.

Two additional sources not included in this study were included in WG3B's estimates: iron and steel sintering and sulfite pulp mills. Insufficient data were found to estimate sulfate emissions from those sources.

The basis for the sulfate emissions data in Table A-1 and the sources of information are given in the remainder of Section A.1.

A.1.1 Electric Utilities

A.1.1.1 National Emissions--Coal-Fired Boilers. Reference 2 presented primary sulfate emission factors for coal-fired utilities. The factors were 0.175 kg (0.385 lbs) and 0.89 kg (1.95 lbs) sulfate emitted per ton of bituminous and lignite coal burned, respectively. WG3B estimated sulfate emissions to be about 1.2 percent of SO_2 emissions from coal-fired utilities.

An estimate of the coal-fired utility capacity controlled with FGD systems was made. A report entitled "Typical Sulfur Dioxide Emissions from Subpart D Power Plants Firing Compliance Coal" [PEDCo Environmental, Inc., March 1984] contains a list of 62 utilities subject to the new source performance standard. The capacity represented by the list represented about 20 percent of the total coal-fired utility capacity (Reference 5). Taking the average emission rate (controlled condensation system tests only) for FGD-controlled sulfate emissions and the average emission rate for ESP-controlled sulfate emissions and weighting them to reflect 20 percent FGD control, results in an emission rates of 0.14 kg (0.30 lbs) sulfate/ton bituminous coal burned and 0.69 kg (1.52 lbs) sulfate/ton lignite coal burned.

A summary of data for sulfate emissions from utility boilers (Reference 2) included the test results shown in Table A-2. This table shows that for a limited number of test sites the range in sulfate emissions

TABLE A-1. NATIONAL SULFATE EMISSIONS

Source Category	Total Sulfate Emissions 10^3 Mg/yr (10^3 tons/yr)	Comments
(1) Utility Boilers		
Coal	107 (117)	100% acid sulfate
Residual Oil	39 (43)	67% acid sulfate
Distillate Oil	7.3 (8)	50% acid sulfate
(2) Industrial Boilers		
Coal	24-95 (26-105)	85% acid sulfate
Residual Oil	10-21 (11-23)	50% acid sulfate
Distillate Oil	52 (57)	55% acid sulfate
(3) Kraft Pulp Mills		
Recovery Boiler	204 (225)	Sulfate is mostly Na_2SO_4 (neutral)
(4) Cement Plants	159 (175)	Particulates (probably refractory)
(5) Gypsum Plants	73 (80)	$CaSO_4$ (neutral)
(6) Catalytic Cracking	11.3 (12.5)	All acid sulfate
(7) Primary Copper	8.6-10.5 (9.5-11.5)	*AZ, NM; all acid sulfate
(8) Claus Plants	5.4 (6)	*MS, WY; all acid sulfate
(9) Coking	5 (5.5)	*PA, IN, OH; all acid sulfate
(10) Sulfuric Acid Plants	1.8 (2)	H_2SO_4 mist
(11) Primary Zinc	0.45 (0.5)	
(12) Primary Aluminum	0.18-0.41 (0.2-0.45)	All acid sulfate
TOTAL	708-792 (778-873)	36% acid sulfate 54% non-acidic sulfate 10% undetermined sulfate

*Possible high local ambient air concentrations.

TABLE A-2. ACID SULFATE EMISSIONS FROM COAL-FIRED UTILITY BOILERS[a]

Coal Type	Boiler Size (MW)	Fuel Sulfur Content (Weight %)	Emission Control	Test Method[b]	Sulfate Emission kg/Mg (lb/ton)
Bituminous	125	0.9	ESP	CCS	0.146 (0.293)
Bituminous	163	0.9	ESP	CCS	0.148 (0.296)
Bituminous	156	3.3	ESP	CCS	0.190 (0.381)
Bituminous	156	3.3	ESP & FGD	CCS	0.134 (0.269)
Bituminous	560	1.0	ESP	CCS	0.081 (0.162)
Bituminous	411	3.5	ESP & FGD	CCS	0.139 (0.279)
Lignite	440	1.38	ESP	Method 6	0.975 (1.951)
Bituminous	700	1.10	None	Method 6	0.813 (1.627)
Bituminous	700	1.10	FGD	Method 6	0.380 (0.761)
Bituminous	468	1.67	ESP	Method 6	0.645 (1.290)
Bituminous	411	4.7	ESP	CCS	0.396 (0.793)
Bituminous	411	4.7	ESP & FGD	CCS	0.240 (0.480)

[a] Source: Reference 2.

[b] CCS = controlled condensation system.

is 0.146 to 0.975 kg (0.293 to 1.951 lbs) per ton of coal. It can be inferred from the limited data set that acid sulfate emission factors in the 0.14 to 0.19 kg (0.3 to 1.5 lbs) per ton range are representative. The data also indicate that FGD systems reduce the amount of sulfates emitted.

The coal-fired utility emissions were extrapolated to a national total using the quantity of coal burned in the utility sector. Reference 6 reports 495 million Mg (545 million tons) of bituminous coal and 43 million Mg (47 million tons) of lignite coal burned in the utility sector in 1982. Applying the bituminous and lignite emission factors results in total national acid sulfate emissions of 107,000 Mg (117,500 tons) per year.

Oil-Fired Boilers. WG3B (Reference 1) estimated sulfate emissions from distillate oil-fired boilers were estimated to be 8.2 percent of SO_2 emissions. Reference 2 normalized those estimates to production rates included in NEDS and estimated (12 lb/1,000 gal) distillate burned. A review of emission data (Reference 2) included tests of 3 oil-fired units. The data are summarized in Table A-3. These data indicate that an emission factor of 1.4 kg/m^3 (12 lb/1,000 gal) may be high by a factor of 2. Reference 2 presents a primary sulfate emission factor for residual oil-fired utility boilers of 0.63 kg/m^3 (5.44 lbs/1,000 gal).

Reference 7 reports 62 million m^3 (390 million barrels) of residual oil fired in the utility sector in 1980. Applying the 0.63 kg/m^3 (5.44 lb/1,000 gal) emission factor to the quantity consumed results in an estimate of national sulfate emissions of 39,000 Mg (43,000 tons) from residual oil-fired utilities.

No sulfate emissions numbers for distillate oil-fired boilers other than the WG3B estimate were found. Reference 2 derived an emission factor of 1.4 kg/m^3 (12 lb/1,000 gal) burned from WG3B's estimate and the production rate data in NEDS. Applying the factor to the total amount of distillate fired in the utility industry (5 million m^3 (32 million barrels)) (Reference 7 results in national sulfate emission estimate of 7,300 Mg (8,000 tons) from distillate oil-fired utility boilers.

WG3B estimated that 65 percent of the total sulfate produced in residual-fired utilities is acid sulfate, while 50 percent of the total sulfate produced in distillate-fired utilities is acid sulfate

TABLE A-3. SULFATE EMISSIONS FROM RESIDUAL OIL-FIRED UTILITY BOILERS

Unit Size[a] (MW)	Fuel Sulfur Content (Weight %)	Emission Controls	Sulfate Emissions kg/1000 m^3 (lb/1,000 Gal)
100	1.88	Fuel Additive	0.61 (5.089)
100	1.72	Fuel Additive	0.67 (5.589)
100	1.45	Fuel Additive	0.68 (5.640)

Source: Reference 2.

[a] Three units at one plant.

(Reference 1). Applying their acid sulfate estimates would indicate that acid sulfate emissions from residual-fired utilities would be about 12,500 Mg (28,000 tons) per year. Similarly, acid sulfate emissions from distillate-fired utility boilers would be about 4 million kg (8 million lbs) per year.

A.1.1.2 Local Emissions. Utility combustion sources appear to be dispersed widely throughout the U.S. However, electric utilities are large sources and high local sulfate ambient air concentrations could result in their vicinity.

A.1.2 Industrial Boilers

A.1.2.1 National Emissions. In the industrial boiler category WG3B estimated sulfate emissions to be 1.6 percent of SO_2 emissions. Reference 2 normalized this estimate to 0.304 kg/Mg (0.608 lb/ton) for anthracite and bituminous coals and 0.240 kg/Mg (0.480 lb/ton) for lignite. Arbitrarily multiplying 0.25 kg/Mg (0.5 lb/ton) by 95 million Mg (105 million tons) of coal used in the industrial sector (Reference 6) results in a national sulfate emissions estimate of 23,600 Mg (26,000 tons) per year.

A review of sulfate emissions data (Reference 2) included 3 test results from coal-fired industrial boilers. (See Table A-4.) The two data points obtained with the CCS method indicate that the actual emission factor may be higher by a factor of 4, considering that FGD systems are not common among industrial boilers. Using a factor of 0.9 kg/Mg (2 lb/ton) coal burned results in an estimate of 95,300 Mg (105,000 tons) sulfate per year. WG3B estimated that 85 percent of the sulfate emissions from non-utility combustion of coal are acid sulfate emissions. Applying this factor would indicate that acid sulfate emissions from industrial coal-fired boilers are about 20,000 to 81,000 Mg/yr (22,000 to 89,000 tons/year).

WG3B estimated emissions of sulfate from oil-fired industrial boilers to be 8.2 percent of SO_2 emissions. Reference 2 presented an emission factor based on WG3B's estimate and combustion rates in NEDS of 1.4 kg sulfate/m^3 (12 lb sulfate/1,000 gal) for distillate oil fired in industrial boilers. No other sulfate emission data were found for distillate oil-fired industrial boilers. Multiplying the 1.4 kg sulfate/m^3 (12 lb

TABLE A-4. ACID SULFATE EMISSIONS FROM COAL-FIRED INDUSTRIAL BOILERS

Boiler Size	Fuel Sulfur Content (Weight %)	Emission Control	Test Method	Acid Sulfate Emissions kg/Mg (lb/ton)
10 MW	1.64	Multiclone	CCS	1.323 (2.646)
10 MW	1.64	Multiclone & FGD	CCS	0.230 (0.462)
100,000 lb steam/hr	0.91	ESP	Method 8	0.099 (0.199)

sulfate/1,000 gal) by the amount of distillate fired in the industrial sector results in an estimate of 52 million kg (114 million lbs) of sulfate from distillate oil-fired industrial boilers. WG3B estimated 50 percent of the sulfate emissions from industrial oil combustion to be acid sulfates. This would indicate that about 27,200 Mg (30,000 tons) of the potential sulfate emissions are acid sulfates.

Results of two tests of one residual-fired industrial boiler were reported (Reference 2) as shown in Table A-5. The primary sulfate emission factors resulting from these tests were 0.63 kg/m^3 (5.30 lbs/1,000 gal) and 0.31 kg/m^3 (2.62 lbs/1,000 gal) for uncontrolled and controlled boilers, respectively. Multiplying these factors by the quantity of residual oil burned in the industrial sector (Reference 7) results in primary sulfate emissions of 10,000 to 21,300 Mg (11,000 to 23,500 tons) per year. Using WG3B's estimate that 50 percent of sulfates produced in industrial oil combustion are acid sulfates, acid sulfates would be about 5,000 to 10,400 Mg (5,500 to 11,500 tons) per year.

A.1.2.2 Local Emissions. Industrial combustion sources appear to be widely dispersed throughout the U.S. No high local sulfate concentrations are expected, but industrialized areas may contribute significant quantities of sulfate emissions from combustion.

A.1.3 Coke Production

A.1.3.1 National Emissions. The WG3B sulfate emissions estimate for coke production is 8.2 percent of the SO_2 emissions. Reference 2 normalized that estimate to the production rate in NEDS and came up with 0.15 kg/Mg (0.3 lb/ton) coal charged. No other sulfate emission data were found. Reference 8 reports 34 million Mg (37 million tons) of coal charged to coke ovens in 1983. Using this quantity as a multiplier, national annual emissions of sulfate from coking are estimated to be 5,000 Mg (5,500 tons). All of the sulfate emissions are thought to be acid sulfate (Reference 1).

TABLE A-5. ACID SULFATE EMISSIONS FROM RESIDUAL OIL-FIRED INDUSTRIAL BOILERS

Boiler Size	Fuel Sulfur Content (Weight %)	Emission Control	Test Method	Primary Sulfate Emissions kg/m^3 (lb/1,000 Gal)
10 MW	1.96	Multiclone	CCS	0.63 (5.296)
10 MW	1.96	Multiclone & FGD	CCS	0.31 (2.616)

A.1.3.2 Local Emissions. As of 1980, Pennsylvania, Indiana, and Ohio accounted for 23, 19, and 16 percent of total U.S. capacity, respectively. However, it is not clear from this information whether local concentrations of sulfate can be expected to be high because of sulfate emissions from coke plants.

A.1.4 Sulfuric Acid Plants

A.1.4.1 National Emissions. WG3B used a sulfate emission factor of 0.05 kg/Mg (0.1 lb/ton) acid produced. Reference 9 reported uncontrolled emissions of 0.18 to 1.8 kg (0.4 to 4 lbs) H_2SO_4 mist per ton of acid produced. The same reference reported that about 5 percent of the acid plants in the U.S. have no controls for acid mist. Reference 10 reported NSPS compliance test data for 29 sulfuric acid plants, representing about 30 percent of the U.S. capacity (References 10,11). The average acid mist emission rate reported was 0.04 kg/Mg (0.08 lb/ton) of acid produced. This value agrees well with the WG3B factor of 0.05 kg/Mg (0.1 lb/ton) which was used in this study.

Extrapolating to the national production rate of 1982 (Reference 11) yields total national sulfate emissions of 1,800 Mg (2,000 tons) per year.

A.1.4.2 Local Emissions. Based on data listed in NEDS, Florida accounts for 55 percent of the domestic sulfuric acid production. If these data are correct, local sulfate concentrations could be high in that region. However, major omissions noted in NEDS data for other industries makes it difficult to judge the reliability of the data.

A.1.5 Gypsum Plants

A.1.5.1 National Emissions. Reference 12 estimates 73,000 Mg/yr (80,000 tons/yr) of particulate emissions from the gypsum industry. If one assumes the particulate matter to be calcium sulfate (neutral in water), one can assume about 55 percent to be sulfate. Using these assumptions results in a national emissions estimate of about 40,000 Mg (44,000 tons) sulfate from gypsum production. This approach is similar to the one used by WG3B.

These data are based on 1973 emissions estimates. However, since sulfate emissions from gypsum plants are assumed to be non-acidic (calcium sulfate), more recent emissions data were not pursued.

A.1.5.2 Local Emissions. Gypsum plants appear to be broadly distributed throughout the U.S. and, thus, significant localized sulfate emissions are not anticipated.

A.1.6 Kraft Pulp Mills

A.1.6.1 National Emissions. WG3B derived a sulfate emission factor of 85 percent of total particulate emissions for Kraft pulp mills. Based on this factor sulfate emissions are estimated to be 29,200 Mg (32,200 tons) per year. WG3B estimated no SO_3 emissions. However, other sources have given estimates for SO_3 emissions. Reference 3 presents SO_3 emission rates from recovery boilers as 0 to 6 kg/Mg (0 to 13 lb/ton) air dried pulp. Using the mid-point of the range and production rates from Reference 13, national emissions of 109,000 Mg SO_3 (120,000 tons SO_3) are estimated. However, to maintain consistency with this and other work in the National Acid Precipitation Assessment Program (NAPAP), WG3B's estimate of no SO_3 emission will be used. Controlled particulate emissions estimates of 0.5 to 25 kg/Mg (1 to 50 lb/ton) are presented in Reference 3. The major constituent is reported to be Na_2SO_4 (neutral in water). Assuming all the particulate emissions from the recovery boiler to be Na_2SO_4, using the production rate of air dried pulp from Reference 12, and using the high side of the range results in a national emissions estimate of 404,000 Mg (445,000 tons) of particulate sulfate. Using a mid-point results in a national emissions estimate of 204,000 Mg (225,000 tons) of sulfate. One other estimate of particulate emissions was found. Reference 13 presents uncontrolled particulate emission rates from the recovery furnace of 22 to 283 kg/Mg (44 to 565 lb/ton) of air dried pulp. It was assumed for purposes of this study that most recovery boilers would be controlled to some degree. Therefore, the controlled emission rate presented in Reference 3 was thought to be more applicable.

A.1.6.2 Local Emissions. NEDS production rate data totals about 27 million Mg (30,000,000 tons) of Kraft pulp. States with the largest production rates and, therefore, the largest estimated sulfate emission potential are (according to NEDS) Alabama, Georgia, and Florida. Alabama accounts for 17 percent of the Kraft Pulping capacity. It is not clear from these numbers whether local concentrations of sulfate can be expected to be high because of sulfate emissions from Kraft pulp mills.

A.1.7 Catalytic Cracking

A.1.7.1 National Emissions. The WG3B sulfate emission factor for catalytic cracking is 0.04 kg/m^3 (15 lb/1,000 bbl) fresh feed. Sulfate emissions data for catalytic cracking units were found in four other sources (References 14, 15, 16, 17). Emissions test data for uncontrolled emissions gave 0.08 and 0.05 kg/m^3 (29 and 16 lb/1,000 bbl) for combined SO_3 and sulfate (Reference 16). Controlled emission rates were about 2 orders of magnitude lower (References 14, 15, 16, 17). The WG3B number agrees closely with the uncontrolled emission rates. Applying the emission factor to the nameplate capacity of 831,540 m^3/sd (5,230,400 bbl/sd) for catalytic cracking in 1983 (Reference 18) gives a national potential emissions estimate of 11,300 Mg (12,500 tons) of sulfate emissions per year. The test data provided in References 14 through 17 indicate that all of the sulfate emissions are acid sulfate.

A.1.7.2 Local Emissions. Catalytic cracking capacity and estimated potential sulfate emissions are highest in Texas which accounts for 30 percent of U.S. capacity. Louisiana accounts for 15 percent. These figures do not indicate any clearly defined areas of high local sulfate concentrations. However, sulfate emissions will be high in areas of Texas and Louisiana where petroleum refineries are concentrated.

A.1.8 Primary Aluminum

A.1.8.1 National Emissions. WG3B estimated that sulfate emissions from primary aluminum smelters were about 0.5 percent of the SO_2 emissions. No other sulfate emissions data were found. Reference 4 estimated that SO_2

emissions would amount to 6 to 13 Mg/day (7 to 14 tons/day) for a 545 Mg/day (600 ton/day) plant. Combining the WG3B factor with the estimate in Reference 4, the sulfate emissions would amount to 0.060 to 0.120 kg/Mg (0.120 to 0.240 lb/ton) aluminum. In 1983, 3,310,000 Mg (3,640,000 tons) of primary aluminum were produced (Reference 19). Based on that production rate, national sulfate emissions from primary aluminum production would then be 180 to 410 Mg (200 to 450 tons) per year. WG3B indicated that the sulfates emitted from aluminum smelters are acid sulfates (Reference 1).

A.1.8.2 Local Emissions. Sulfate emissions from individual aluminum smelters appear to be low, and high local sulfate concentration would not be expected.

A.1.9 Primary Copper

A.1.9.1 National Emissions. WG3B estimated that two tons of SO_2 are generated per ton of copper produced in primary copper smelters. They also estimated that acid sulfates emissions equal 1.35 percent of SO_2 emissions. Combining these factors yields an emissions estimate of 25 kg (54 lbs) of acid sulfate per ton of copper smelted. Sulfuric acid emissions data were found in two test reports for copper smelters. Both were tests of scrubbers on electric slag cleaning furnaces. Sulfuric acid levels for both scrubbers were 0.14 kg/hr (0.03 lb/hr) at the scrubber inlet and 0.03 kg/hr (0.07 lb/hr) at the scrubber outlet (References 20, 21). It was unclear from the test reports how these values could be related to the copper production rate at the smelter.

Reference 22 reported 1.16 million tons of copper smelted in the U.S. in 1984. Reference 23 estimated 70 percent control of SO_2 at copper smelters. Applying these estimates to the WG3B emissions factor of 27 kg acid sulfate/Mg (54 lbs acid sulfate/ton) copper smelted yields 8,600 Mg (9,500 tons) of acid sulfates. Reference 23 also estimated 2,177 kg (4,800 lbs) SO_2 generated/ton copper smelted. Combining this with the WG3B estimate of 0.0061 kg (0.0135 lbs) acid sulfate/lb SO_2 and assuming

TABLE A-6. DOMESTIC PRIMARY COPPER SMELTERS

Company	Location	Annual Capacity Mg	Annual Capacity Tons
ASARCO, Incorporated	El Paso, Texas	91,000	100,000
	Hayden, Arizona	182,000	200,000
Tennessee Chemical Company	Copperhill, Tennessee	13,600	15,000
Copper Range Company	White Pine, Michigan	52,000	57,000
Inspiration Consolidated Copper Company	Miami, Arizona	136,000	150,000
Kennecott Minerals Company (SOHIO)	Hayden, Arizona	71,000	78,000
	Hurley, New Mexico	73,000	80,000
Magma Copper Company	San Manuel, Arizona	181,000	200,000
Phelps Dodge Corporation	Douglas, Arizona	115,000	127,000
	Hidalgo, New Mexico	163,000	179,000

Source: Reference 23, p. 3-2.

70 percent control yields 10,400 Mg (11,500 tons) of acid sulfate. Thus, total domestic acid sulfates emissions from primary copper smelters are 8,600 to 10,400 Mg (9,500 to 11,500 tons) per year.

A.1.9.2 Local Emissions. Table A-6 shows locations and capacities for primary domestic copper smelters. The vast majority are located in the Western U.S. In fact, Arizona and New Mexico account for 80 percent of domestic capacity. This area may see high concentrations of sulfate from copper smelters.

A.1.10 Primary Zinc

A.1.10.1 National Emissions. Reference 2 reported a sulfate emission factor for primary zinc smelting of 27.7 kg/Mg (55.5 lb/ton) processed. This emission factor was derived from WG3B's estimate of 5 percent of SO_2 emissions and the production rate data in NEDS. No other sulfate emissions estimates were found for zinc smelters. Reference 24 reported 261,750 Mg (288,525 tons) of slab zinc smelted in 1983. These figures would indicate that uncontrolled emissions of sulfate from domestic primary zinc smelters would be about 16 million pounds per year. Controlled sulfate emissions from zinc smelters are expected to be much lower. All currently operating primary zinc smelters in the U.S. employ contact sulfuric acid plants for SO_2 control (Reference 25). These acid plants achieve a 96 percent SO_2 removal efficiency (Reference 1). Since the process involves high efficiency acid mist elimination and SO_3 absorption, concurrent sulfate control is assumed. This yields controlled sulfate emissions of 450 Mg (500 tons) per year. It is unclear whether the smelter related acid plants are included in the sulfuric acid plant category (Section A.1.4) or are a separate source category.

A.1.10.2 Local Emissions. Table A-7 shows primary zinc smelters in the U.S. Using WG3B's estimate of 5 percent of the SO_2 emissions, the following emissions estimates were derived (Reference 26) for some of the zinc smelter acid plants:

- Jersey Miniere Zinc/Clarksville, TN: about 435 Mg/yr (478 tons/yr) SO_2; about 21.3 Mg sulfate/yr (23.5 tons sulfate/yr).

TABLE A-7. DOMESTIC PRIMARY ZINC SMELTERS

Plant	Location	Capacity[a] Mg/yr (tons/yr)	Sulfate Emissions Mg/yr (tons/yr)
ASARCO/Corpus Christi	Corpus Christi, Texas	100,000 (110,000)	15.5 (17.0)
AMAX/Sauget	Sauget, Illinois	72,700 (80,000)	18.2 (20.0)
Jersey Miniere Zinc	Clarksville, Tennessee	81,800 (90,000)	21.4 (23.5)
National Zinc	Bartlesville, Oklahoma	50,900 (56,000)	-- --
St. Joe/Monaca	Monaca, Pennsylvania	90,900 (100,000)[b]	-- --

[a] Zinc production capacity.

[b] This includes 80,000 tons/yr of zinc and 20,000 tons/yr zinc equivalent of zinc oxide.

- AMAX/Sauget, IL: about 360 Mg/yr (400 tons/yr) SO_2; 18 Mg sulfate/yr (20 tons sulfate/yr).

- ASARCO/Corpus Christi, TX: about 305 Mg/yr (335 tons/yr) SO_2; about 15.5 Mg sulfate/yr (17 tons sulfate/yr).

A.1.11 Cement Plants

A.1.11.1 National Emissions. WG3B's uncontrolled sulfate emission factor is 2.8 kg sulfate/Mg (5.6 lb sulfate/ton) cement (Reference 2). Reference 27 reports finished cement capacity of 95 million Mg (104 million tons) and a capacity utilization of about 0.6 for 1983. Combining these numbers to get a production rate and applying the 2.8 kg/Mg (5.6 lb/ton) emission factor results in a national sulfate emissions estimate of 160,000 Mg (175,000 tons) from cement production. The particulate emissions from cement manufacture are expected to be of a refractory nature and, therefore, not very soluble in water. Thus, they would not readily form acid deposition.

A.1.11.2 Local Emissions. Based on data from NEDS, no one state has more than 10 percent of the U.S. cement plant capacity. Thus, no high local sulfate concentrations are anticipated.

A.1.12 Claus Plants

A.1.12.1 National Emissions. The sulfate emission factor derived by WG3B for Claus plants is 1 percent of the SO_2. Reference 2 presented an emission factor normalized to the NEDS production rate data of 1.4 kg/Mg (2.8 lb/ton) of sulfur processed (Reference 2). No other sulfate emissions data were found. Reference 28 reports that sulfur recovered from petroleum refineries and natural gas plants amounted to 39,000 Mg (4.3 million tons) in 1980. Combining the two factors, national sulfate emissions from Claus plants would be about 5,400 Mg/yr (6,000 tons/yr). All of the sulfate emissions from Claus plants are thought to be acid sulfate (Reference 1).

A.1.12.2 Local Emissions. Reference 28 reports that 49 Claus plants are located in Texas, 10 in New Mexico, 13 in Mississippi-Alabama-Florida, and 8 in Wyoming. Neither production rate nor capacity are presented by state, however, except for companies with only one plant. Two of these are very large, each accounting for 10 percent of the U.S. capacity. It is possible that high sulfate levels could occur in the vicinity of Claus plants as large as those. Also, if the Claus plants in Texas and New Mexico are concentrated in local areas, local sulfate concentrations could be high.

A.2 CHLORIDE EMISSION SOURCES

This section contains an analysis of available information on HCl emissions from industrial sources and electric utilities. The approach used was to use the best existing data; no new information was generated. The sources of this information include Source Assessment Documents, Control Technology Guidelines, and other references.

The overall results of the study of HCl emissions are shown in Table A-8. As the table shows, the highest national emissions were estimated for utility and industrial boilers. Possible high local HCl levels were also suggested in the vicinity of propylene oxide plants.

Incinerators also have high HCl emissions. Emission factors were available for municipal solid waste, industrial waste, and liquid waste. However, the basis for the factors for industrial or liquid waste were not explained adequately, so emissions estimates for these wastes could not be made.

The basis for the HCL emissions data in Table A-8 and the sources of information are given in the remainder of Section A.2.

A.2.1 Coal-Fired Utility Boilers

A.2.1.1 National Emissions. Reference 31 gives HCl emissions from 46 sites across the country. These measurements were obtained using an EPA source assessment sampling system (SASS) train. From these tests an HCl emission factor of 33.9 ng/J (78.8 lb/10^9 Btu) was obtained. This factor was based on the use of bituminous coal. Assuming a heating value of 30,200 kJ/kg (13,000 Btu/lb),[30] the emission factor becomes 1.0 kg/Mg (2.0 lb/ton) of bituminous coal burned. Emission factors for lignite and anthracite coal were obtained in the same manner yielding 0.01 kg/Mg (0.02 lb/ton) lignite and 0.5 kg/Mg (1.0 lb/ton) anthracite burned.

TABLE A-8. HCl EMISSIONS

Source Category	National HCl Emissions 10^3 Mg (10^3 tons)
(1) Utility Boilers	496 (546)
(2) Industrial Boilers	88 (96)
(3) Incineration	
Industrial Waste	[a]
Municipal Solid Waste	20 (22)
Liquid Waste	[a]
(4) Propylene Oxide[b] Manufacturing	1.9 (2.1)
(5) Residential Boilers	
Anthracite Coal	1.3 (1.48)
Bituminous Coal	1.4 (1.5)
Lignite Coal	0.004 (0.005)

[a] Specific data lacking.

[b] Possible high local emissions in TX/LA area.

Reference 6 reports 495 million Mg (545 million tons) bituminous, 43 million Mg (47 million tons) lignite, and 0.9 million Mg (1.0 million tons) anthracite coal burned in the utility sector in 1982. Multiplying the emission factors by the national combustion rates results in total HCl emissions of 496,000 Mg (546,000 tons) per year.

A.2.1.2 Local Emissions. Utility combustion sources appear to be dispersed widely throughout the U.S. However, electric utilities are large sources and could result in high local HCl levels.

A.2.2 Coal-Fired Industrial Boilers

A.2.2.1 National Emissions. Reference 31 gives HCl emissions from 32 sites across the country. These measurements were obtained using an EPA SASS train. From these tests an HCl emission factor of 33.9 ng/J (78.8 lb/10^9 Btu) was obtained. This factor was based on the use of bituminous coal. Assuming a heating value of 30,000 kJ/kg (13,000 Btu/lb), the emission factor becomes 1.0 kg/Mg (2.0 lb/ton) of bituminous coal burned. Factors of 0.01 kg/Mg (0.02 lb/ton) lignite and 0.5 kg/Mg (1.0 lb/ton) anthracite burned were obtained in the same manner.

Reference 6 reports 87 million Mg (96 million tons) bituminous, 7 million Mg (8 million tons) lignite, and 0.5 million Mg (0.6 million tons) anthracite burned in the industrial sector in 1982. Multiplying the emission factors by these national combustion rates results in total HCl emissions of 88,000 Mg (96,500 tons) per year.

A.2.2.2 Local Emissions. Industrial combustion sources appear to be widely dispersed throughout the U.S.; thus, no high local HCl levels are anticipated.

A.2.3 Coal-Fired Residential Boilers

A.2.3.1 National Emissions. Reference 32 gives HCl emissions for anthracite, bituminous, and lignite coal. These emission factors are 52 ng/J (120 lb/10^9 Btu), 26 ng/J (60.5 lb/10^9 Btu), and 15 ng/J (35.1 lb/10^9 Btu). Little information was given concerning the basis for these emission factors. Heating values of 31,400 kJ/kg (13,500 Btu/lb) for anthracite, 30,000 kJ/kg (13,000 Btu/lb) for bituminous, and 16,800 kJ/kg

Reference 6 reports 495 million Mg (545 million tons) bituminous, 43 million Mg (47 million tons) lignite, and 0.9 million Mg (1.0 million tons) anthracite coal burned in the utility sector in 1982. Multiplying the emission factors by the national combustion rates results in total HCl emissions of 496,000 Mg (546,000 tons) per year.

A.2.1.2 Local Emissions. Utility combustion sources appear to be dispersed widely throughout the U.S. However, electric utilities are large sources and could result in high local HCl levels.

A.2.2 Coal-Fired Industrial Boilers

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Reference 6 reports 87 million Mg (96 million tons) bituminous, 7 million Mg (8 million tons) lignite, and 0.5 million Mg (0.6 million tons) anthracite burned in the industrial sector in 1982. Multiplying the emission factors by these national combustion rates results in total HCl emissions of 88,000 Mg (96,500 tons) per year.

A.2.2.2 Local Emissions. Industrial combustion sources appear to be widely dispersed throughout the U.S.; thus, no high local HCl levels are anticipated.

A.2.3 Coal-Fired Residential Boilers

A.2.3.1 National Emissions. Reference 32 gives HCl emissions for anthracite, bituminous, and lignite coal. These emission factors are 52 ng/J (120 lb/10^9 Btu), 26 ng/J (60.5 lb/10^9 Btu), and 15 ng/J (35.1 lb/10^9 Btu). Little information was given concerning the basis for these emission factors. Heating values of 31,400 kJ/kg (13,500 Btu/lb) for anthracite, 30,000 kJ/kg (13,000 Btu/lb) for bituminous, and 16,800 kJ/kg

(7,200 Btu/lb) for lignite were assumed. This gives emission factors of 1.6 kg/Mg (3.2 lb/ton) for anthracite, 0.8 kg/Mg (1.6 lb/ton) for bituminous, and 0.25 kg/Mg (0.5 lb/ton) for lignite burned.

Reference 32 reports that 850,000 Mg (937,000 tons) of anthracite, 1.74 million Mg (1.92 million tons) of bituminous, and 20,000 Mg (22,000 tons) of lignite coal were burned in 1974. Based on the emission factors given above, annual estimates of HCl production are 1,400 Mg (1,500 tons) for anthracite coal, 1,400 tons (1,500 tons) for bituminous coal and 4.5 Mg (5 tons) for lignite.

A.2.3.2 Local Emissions. As shown in Figure A-1 the majority of coal that is burned in residential boilers is consumed in the northeastern U.S. Because of the relatively low amount of coal burned nationwide by residential boilers, high local HCl levels are not expected.

A.2.4 Propylene Oxide Manufacturing

A.2.4.1 National Emissions. Reference 34 gives an emission factor of 7.46 HCl per ton of propylene oxide produced. Reference 35 gives total production from propylene oxide plants in 1980 as 0.52 million Mg (0.57 million tons). Using the emission factor of 3.7 kg HCl/Mg (7.46 lb HCl/ton) gives national emissions of 1,930 Mg/yr (2,120 tons/yr).

A.2.4.2 Local Emissions. Three propylene oxide plants are located in the Texas/Louisiana area and produce 0.42 Mg/yr (0.64 tons/yr) or 80 percent of the national production. Emissions from these three plants are 1,500 Mg (1,700 tons) of HCl per year. HCl could contribute to local problems in these two states.

A.2.5 Incineration

A.2.5.1 Industrial Waste. Reference 31 gives an emission factor of 2.43 kg (5.35 lb) HCl per ton of waste burned. However, the reference does not provide details concerning how this emission factor was derived. No other information could be found to support or refute this factor.

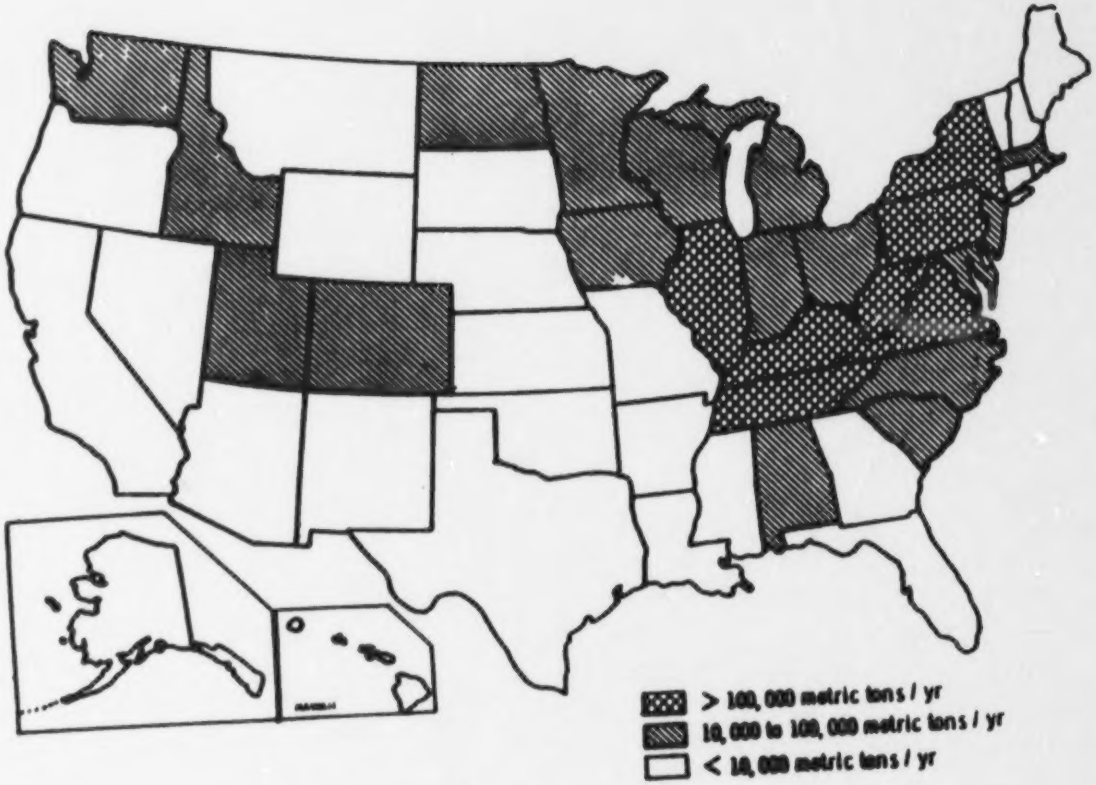

▩ > 100,000 metric tons / yr
▨ 10,000 to 100,000 metric tons / yr
☐ < 10,000 metric tons / yr

Figure A-1. Estimated residential coal consumption in 1974 by state.[35]

A.2.5.2 Municipal Solid Waste (MSW). Reference 31 gives an emission factor of 2.3 kg (5.0 lbs) HCl per ton of MSW burned. This factor is based on the results from three municipal incinerators that were tested for uncontrolled emissions. No information was available concerning the accuracy of the emission test that was done. Reference 36 indicates that 8 million Mg (8.8 million tons) of MSW are incinerated per year. Based on this amount, 20,000 Mg (22,000 tons) of HCl are produced per year from the combustion of MSW.

A.2.5.3 Liquid Wastes. Liquid wastes such as polychlorinated waste, waste oil, and various other hydrocarbon liquids produce HCl when incinerated. Reference 31 gives an emission factor of 0.59 kg of HCl per Mg (1.19 lbs of HCl per ton) of liquid waste burned. This factor is based on the results from "several" uncontrolled sites. However, no information was available concerning these sites or the type of test done.

A.3 FLUORIDE EMISSION SOURCES

This section contains an analysis of available information on HF emissions from industrial sources and electric utilities. The approach used was to use the best existing data; no new information was generated. The sources of this information include Source Assessment Documents, Control Technology Guidelines, and other references.

The overall results of the study of HF emissions are shown in Table A-9. As the table shows, highest national emissions were estimated for utility and industrial boilers. Possible high local HF levels were indicated in the vicinity of primary aluminum smelters.

Clay and glass plants also have HF emissions. However, not enough information was available on which to make an emissions estimate.

The basis for the HF emissions data in Table A-9 and the sources of information are given in the remainder of Section A.3.

A.3.1 Coal-Fired Utility Boilers

A.3.1.1 National Emissions. Reference 31 gives HF emissions from 46 sites across the country. These measurements were obtained using an EPA

TABLE A-9. HF EMISSIONS

	Source Category	National HF Emissions 10^3 Mg/yr	(10^3 tons/yr)
(1)	Utility Boilers	60	(66)
(2)	Industrial Boilers	10.6	(11.6)
(3)	Gypsum Ponds	5.9	(6.5)
(4)	Primary Aluminum Industry*		
	Anode Baking Furnace		
	Prebake Reduction Cell	2.6	(2.9)
	Verticle Sodderberg Cell	1.5	(1.65)
	Horizontal Soderberg Cell	1.95	(2.15)
(5)	Phosphoric Acid Production	0.14	(0.15)
(6)	Triple Super-Phosphate Manufacturing	0.18	(0.2)
(7)	Diammonium Phosphate Manufacturing	0.23	(0.25)
(8)	Residential Boilers		
	Anthracite Coal	0.05	(0.06)
	Bituminous Coal	0.15	(0.17)
	Lignite Coal	0.001	(0.001)
(9)	HF Manufacturing	0.02-1.3	(0.02-1.4)

*Possible high local concentrations in KY and WA areas.

SASS train. From these tests an HF emission factor of 4.0 ng/J (9.4 lb/10^9 Btu) was obtained. This factor was based on the use of bituminous coal. Assuming a heating value of 30,200 kJ/kg (13,000 Btu/lb)[30], the emission factor becomes 0.12 kg/Mg (0.24 lb/ton) of bituminous coal burned. Emission factors of 0.01 kg/Mg (0.02 lb/ton) lignite and 0.1 kg/Mg (0.2 lb/ton) anthracite coal burned were obtained in the same manner.

Reference 6 reports 495 million Mg (545 million tons) bituminous, 43 million Mg (47 million tons) lignite, and 0.9 million Mg (1.0 million tons) anthracite burned in the utility sector in 1982. Multiplying the emission factors by the national combustion rates results in total HF emissions of 60,000 Mg (66,000 tons) per year.

A.3.1.2 Local Emissions. Utility combustion sources appear to be dispersed widely throughout the U.S. However, electric utilities are large sources, so high local HF concentrations could result in their vicinity.

A.3.2 Coal-Fired Industrial Boilers

A.3.2.1 National Emissions. Reference 31 gives HF emissions from 32 sites across the country. These measurements were obtained using an EPA SASS train. From these tests an HF emission factor of 4.0 ng/J (9.4 lb/10^9 Btu) was obtained. This factor was based on the use of bituminous coal. Assuming a heating value of 30,200 kJ/kg (13,000 Btu/lb)[30], the emission factor becomes 0.12 kg/Mg (0.24 lb/ton) of bituminous coal burned. Emission factors of 0.01 kg/Mg (0.02 lb/ton) lignite and 0.1 kg/Mg (0.2 lb/ton) anthracite burned were obtained in the same manner.

Reference 6 reports 87 million Mg (96 million tons) bituminous, 7 million Mg (8 million tons) lignite, and 0.5 million Mg (0.6 million tons) anthracite burned in the industrial sector in 1982. Multiplying the emission factors by the national combustion rates results in 10,600 Mg (11,650 tons) of HF emissions per year.

A.3.2.2 Local Emissions. Industrial combustion sources appear to be widely dispersed throughout the U.S.; thus no high local HF levels are anticipated.

A.3.3 Coal-Fired Residential Boilers

Reference 31 gives HF emissions for anthracite, bituminous, and lignite coal as 2.1 ng/J (4.95 lb/10^9 Btu), 3.0 ng/J (6.87 lb/10^9 Btu), and 2.7 ng/J (6.34 lb/10^9 Btu), respectively. Little information was given concerning the basis for these emission factors. Heating values of 31,400 kJ/kg (13,500 Btu/lb) for anthracite, 30,200 kJ/kg (13,000 Btu/lb) for bituminous, and 16,700 kJ/kg (7,200 Btu/lb) for lignite were assumed.[30] This gives emission factors of 0.06 kg/Mg (0.13 lb/ton) of anthracite, 0.09 kg/Mg (0.18 lb/ton) of bituminous, and 0.05 kg/Mg (0.09 lb/ton) of lignite burned.

Reference 32 reports that 850,000 Mg (937,000 tons) of anthracite, 1.74 million Mg (1.92 million tons) of bituminous, and 20,000 Mg (22,000 tons) of lignite coal were burned in 1974. Based on the emission factors given above, annual estimates of HF emissions are 54 Mg (60 tons) for anthracite coal, 150 Mg (170 tons) for bituminous coal, and 907 kg (2,000 lbs) for lignite.

A.3.4 HF Manufacturing

Reference 31 gives HF emission factors of 12.5 kg/Mg (25.0 lb/ton) of product for uncontrolled plants and 0.1 kg/Mg (0.2 lb/ton) of product for controlled plants. These emission factors were based on a study of four manufacturing plants. However, very little is known about the accuracy of these tests. In 1980, 193 x 10^3 Mg (213 x 10^3 tons) of HF was produced.[31] Assuming 100 percent control, this production yields 19.3 Mg (21.3 tons) HF emissions per year. Assuming 50 percent control yields 1,220 Mg (1,340 tons) HF emissions per year.

A.3.5 Phosphoric Acid Production

Reference 31 gives an uncontrolled HF emission factor of 0.21 kg/Mg (0.42 lb/ton) of phosphate rock processed. As a result of control by scrubbers, it is estimated that a typical emission factor of approximately 0.015 kg HF/Mg (0.030 lb HF/ton) of P_2O_5 or 0.005 kg HF/Mg (0.010 lb HF/ton) of phosphate rock processed can be used to represent HF emissions from phosphoric acid production. This estimate is based on the fact that all wet-process plants located in Florida are required to achieve an emission limit of 0.01 kg total fluoride/Mg (0.02 lb total fluoride/ton) of P_2O_5. It is estimated that 74 percent of production is in attainment with the 0.02 level. The remaining 26 percent ranges from 0.010 to 0.035 kg total fluroide/Mg (0.020 to 0.070 lb total fluoride/ton) P_2O_5. Also, all wet-process plants built since 1967 are assumed to have installed spray-crossflow packed bed scrubbers. With a 1980 wet-process phosphoric acid production of about 9 million Mg (10 million tons) per year, total HF emissions would be 140 Mg (150 tons) per year.

A.3.6 Gypsum Ponds In Phosphoric Acid Plants

Reference 38 gives an emission factor based on measurements of gypsum ponds at two different phosphate fertilizer plants in Florida. This factor is 0.64 kg/Mg (1.28 lb/ton) of phosphoric acid. Based on a national production of phosphoric acid of 9.3 million Mg (10.2 million tons) given in "Review of New Source Performance Standards for Phosphate Fertilizer Industry - Revised" [U.S. Environmental Prtoection Agency, Research Triangle Park, NC, November 1980], 5,900 Mg (6,500 tons) of HF are emitted yearly from gypsum ponds in the U.S.

A.3.7 Triple Super-Phosphate Manufacturing (TSP)

The major sources of fluoride emissions from a granular TSP plant are the reactors, den, granulator, dryer and cooler. Uncontrolled emissions from these sources have been estimated at a rate of 10.5 kg F/Mg (21.0 lbs F/ton) P_2O_5 input.[31] A controlled emission factor of 0.12 kg F/Mg (0.24 lbs F/ton) P_2O_5 input from granulator plants is reported. Assuming that most of the fluorides are emitted in the form of hydrogen fluoride results in uncontrolled and controlled emission factors of 10.5 and 0.12 kg HF/Mg (21.0 and 0.24 lbs HF/ton) P_2O_5 input, respectively. Reference 39 reports the national production of TSP in 1980 was 1.54 million Mg (1.69 million tons). Based on the controlled factor, annual HF emissions are estimated to be 180 Mg (205 tons).

A.3.8 Diammonium Phosphate Manufacturing

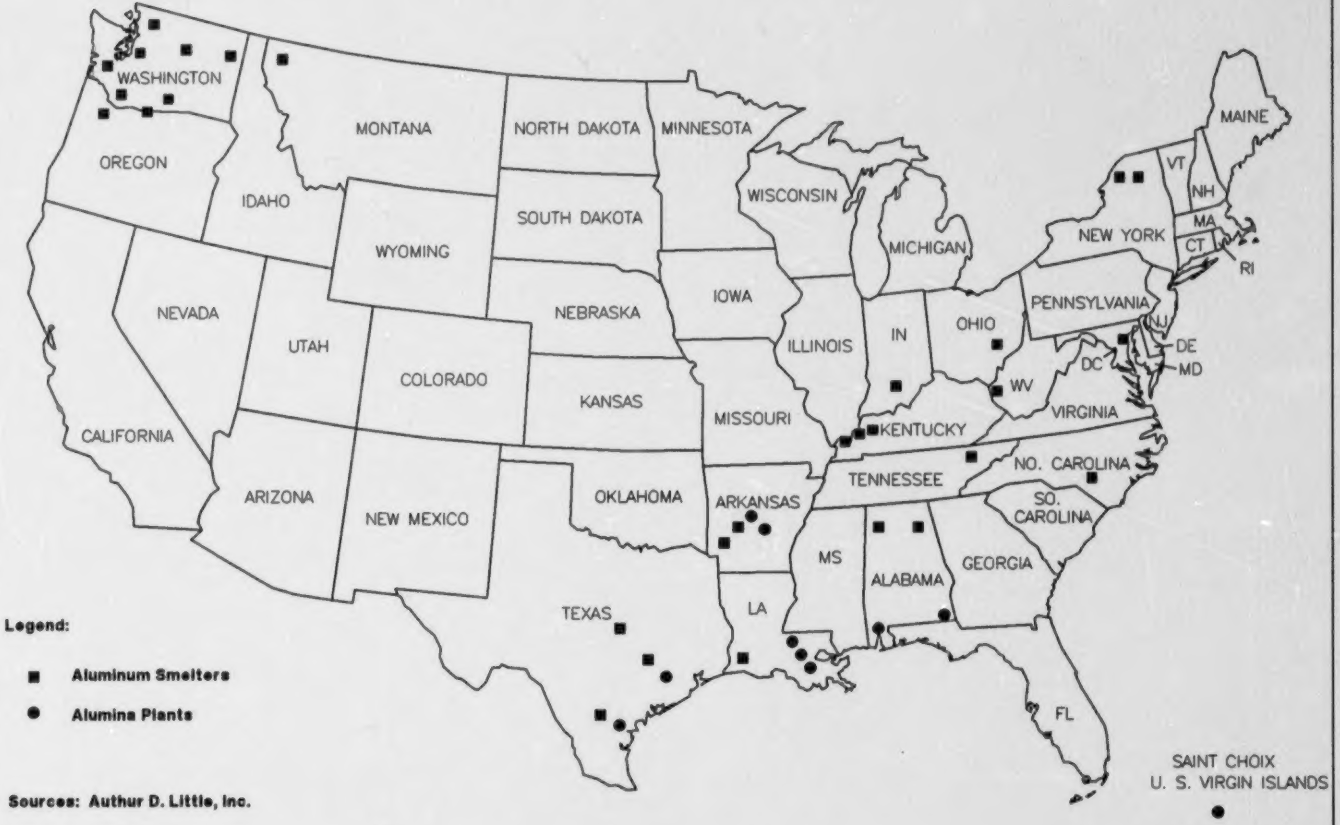
Reference 31 reports a controlled emission factor of 0.04 kg F/Mg (0.08 lb F/ton) of diammonium phosphate fertilizer produced. Reference 39 gives the 1980 national production of diammonium phosphate as 5.6 million Mg (6.1 million tons). Assuming that most of the fluorides are emitted as HF results in annual HF emissions of 210 Mg (250 tons).

A.3.9 Primary Aluminum Industry

Reference 40 breaks down the HF emission factors for the primary aluminum industry by the type of process used. These emission factors are 0.26 kg/Mg (0.52 lb/ton) for anode baking furnaces, 0.86 kg/Mg (1.72 lb/ton) for prebake reduction cells, 2.7 kg/Mg (5.5 lb/ton) for vertical Soderberg (VS) cells and 2.0 kg/Mg (4.1 lb/ton) for horizontal Soderberg (HS) cells. No information was provided by this reference concerning the basis on which emission factors were derived.

Reference 40 also gives the annual production capacity of aluminum in 1975. Anode baking furnaces are not included in these production estimates. However, the capacity of prebake reduction cells was estimated as 3.1 million Mg (3.4 million tons). The capacity of HS cells was estimated at 0.91 million Mg (1.0 million tons) and VS cells at 0.54 million Mg (0.6 million tons). Based on these capacities, HF emissions are estimated at 2,600 Mg (2,900 tons) from prebake reduction cells, 1,500 Mg (1,650 tons) from VS cells and 1,950 Mg (2,150 tons) from HS cells.

Figure A-2 shows the geographical distribution of U.S. aluminum smelters. As can be seen in this figure smelters are spread across the eastern U.S. and in the northwestern corner of the country. Concentration of smelters occurs in the northwestern corner of the U.S. and in the western Kentucky area. Significant local problems could occur in these two areas.


WASHINGTON
OREGON
CALIFORNIA
NEVADA
IDAHO
MONTANA
WYOMING
UTAH
ARIZONA
COLORADO
NEW MEXICO
NORTH DAKOTA
SOUTH DAKOTA
NEBRASKA
KANSAS
OKLAHOMA
TEXAS
MINNESOTA
IOWA
MISSOURI
ARKANSAS
LA
WISCONSIN
ILLINOIS
MICHIGAN
IN
OHIO
KENTUCKY
TENNESSEE
MS
ALABAMA
GEORGIA
FL
SO. CAROLINA
NO. CAROLINA
VIRGINIA
WV
DC
PENNSYLVANIA
NEW YORK
NJ
DE
MD
VT
NH
MA
CT
RI
MAINE
SAINT CHOIX
U. S. VIRGIN ISLANDS
Legend:
■ Aluminum Smelters
● Alumina Plants

Sources: Authur D. Little, Inc.

Figure A–2. Location of alumina plants and aluminum smelters in the United States.

TABLE A-10. SUMMARY OF NO_2 AND NITRATE EMISSIONS ESTIMATES

	NO_2 10^3 Mg (10^3 tons)	Nitrate 10^3 Mg (10^3 tons)
Utility Boilers	318 (350)	64 (70)
Industrial Boilers	136 (150)	32 (35)
Industrial Processes		
HNO_3 Production	64 (70)	--
Adipic Acid	14 (15)	Not Available
Organic Nitration	1.4 (1.5)	Not Available
Nitrocellulose	15 kg/Mg (30 lb/ton)	9.5 kg/Mg (19 lb/ton)

A.4 NITRATE EMISSION SOURCES

National annual estimates of nitrate and NO_2 emissions from electric utilities and industrial sources are shown in Table A-10. In many cases nitrate emissions data were unavailable, but NO_2 data were available. Since NO_2 is soluble in water, some fraction of the NO_2 will be emitted as HNO_3. As shown by Table A-10, the combustion sources are the largest potential emitters of NO_2 and nitrates.

A.4.1 Utility and Industrial Boilers

Most references consulted agreed that NO_2 directly emitted from boilers ranges up to about 5 percent of the total NO_x emissions. Since NO_2 is soluble in water (1.26 g/l) a portion will be emitted in the form of HNO_3. However, no information estimating the portion emitted as HNO_3 was available.

One value for nitrate emissions from utility boilers was found (Reference 41). That value was about 0.04 kg/Mg (0.08 lb/ton) coal combusted. Applying this factor to the total coal combusted in the utility sector, emissions would be estimated to be less than 1 percent of the total NO_x emissions. Because no other information was available, nitrate emissions were estimated to be 1 percent of the total NO_x emissions from utility boilers. This results in about 64,000 Mg (70,[illegible]0 tons) of nitrate emissions per year. The same factor was used for estimating emissions from industrial boilers, yielding 32,000 Mg (35,000 tons) of nitrate emissions per year.

A.4.2 Industrial Processes

Sources in the literature used for this study mentioned adipic acid, nitration reactions, explosives, and nitric acid production processes as potential sources of nitrate emissions.

Information in Reference 41 resulted in estimates of 6,00 to 14,000 Mg (7,000 to 15,000 tons) NO_2 emissions from adipic acid production. There was no indication that any of this was HNO_3, however.

Total NO_x emissions from organic nitrations were estimated to be 1,400 Mg (1,500 tons) (Reference 41). There was no indication of what quantity of these emissions could be expected to be HNO_3.

Manufacture of nitrocellulose was estimated (Reference 41) to emit 9.5 kg (19 lb) HNO_3 mist per ton of product and 15 kg (30 lb) NO_2 per ton of product. No national production levels were found to extrapolate these factors to national emission levels.

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APPENDIX B

IBCOST AND RCUCM SAMPLE TABLES

TABLE B-1. NOMENCLATURE USED IN IBCOST ALGORITHMS

---

1. Capital Costs

EQUP = Equipment
INST = Installation
TD = Total Direct
IND = Indirect (Engineering, Field, Construction, Start-up, and other miscellaneous costs)
TDI = Total Direct and Indirect
CONT = Contingencies
TK = Turnkey
LAND = Land
WC = Working Capital
TOTL = Total Capital

2. Operation and Maintenance Costs[a]

DL = Direct Labor
SPRV = Supervision Labor
MANT = Maintenace Labor
SP = Spare Parts
ELEC = Electricity
UC = Utilities and Chemicals
WTR = Water
SW = Solid Waste Disposal
SLG = Sludge Waste Disposal
LW = Liquid Waste Disposal
SC = Sodium Carbonate
LMS = Limestone
LIME = Lime
FUEL = Fuel
TDOM = Total Direct Operation and Maintenance
OH = Overhead
TOTL = Total Operation and Maintenance

3. Annualized Costs

CR = Capital Recovery
WCC = Working Capital Charges
MISC = Miscellaneous (G & A, Taxes, Insurance)
TCC = Total Capital Charges
TOTL = Total Annualized Charges

TABLE B-1. NOMENCLATURE USED IN IBCOST ALGORITHMS (Continued)

---

4. Boiler Specifications

Q = Thermal Input (10^6 Btu/hr) MW)^b
FLW = Flue Gas Flowrate (acfm) (m^3/s)^b
CF = Capacity Factor (-)^c
BCRF = Capital Recovery Factor for Boiler System

5. Fuel Specifications

FC = Fuel Cost (\$/10^6 Btu) (\$MJ)^b
H = Heating Value (Btu/lb) (KJ/kg)^b
S = Sulfur Content (percent by weight)
A = Ash Content (percent by weight)
N = Fuel Nitrogen Content (percent by weight)

6. SO_2 Control Specifications

UNCSO2 = Uncontrolled SO_2 Emissions (lb/10^6 Btu) (ng/J)^b
CTRSO2 = Controlled SO_2 Emissions (lb/10^6 Btu) (ng/J)^b
EFFSO2 = SO_2 Removal Efficiency (percent)
CRFSO2 = Capital Recovery Factor for SO_2 Control System

7. PM Control Specifications

UNCPM = Uncontrolled PM Emissions (lb/10^6 Btu) (ng/J)^b
CTRPM = Controlled PM Emissions (lb/10^6 Btu) (ng/J)^b
EFFPM = PM Removal Efficiency (percent)
CRFPM = Capital Recovery Factor for PM Control System

8. Cost Rates

ELEC = Electricity Rate (\$/kw-hr)
WTR = Water Rate (\$/10^3 gal) (\$/m^3)^b
ALIME = Lime Rate (\$/ton) \$/kg)^b
ALS = Limestone Rate (\$/ton) (\$/kg)^b
SASH = Sodium Carbonate Rate (\$/ton) (\$/kg)^b
SLDG = Sludge Disposal Rate (\$/ton) (\$/kg)^b
SWD = Solid Waste Disposal Rate (\$/ton) (\$kg)^b
LWD = Liquid Waste Disposal Rate (\$/10^3 gal) (\$/m^3)^b
DLR = Direct Labor Rate (\$/man-hr)
SLR = Supervision Labor Rate (\$/man-hr)
AMLR = Maintenance Labor Rate (\$/man-hr)

TABLE B-1. NOMENCLATURE USED IN IBCOST ALGORITHMS (Continued)

9. NO_x Control Specifications

FFAC = F-Factor (dscf/10^6 Btu)
UNCEA = Uncontrolled Excess Air (%)
CTREA = Controlled Excess Air (%)
DELT = Change in the flue gas exit temperature due to the elimination of the air preheater or a reduction in its effectiveness.
$CRFNO_x$ = Capital Recovery Factor for NO_x Control System

---

[a] Cost categories are not mutually exclusive. For example, some costing routines include electricity and waste cost in the utilities category while others calculate these costs separately.

[b] FGD algorithms use metric units.

[c] (-) factor presented as fraction, not as percent.

TABLE B-2. CALCULATIONS COMMON TO IBCOST ALGORITHMS

1. Capital Costs

EQUP + INST = TD[a]
IND = 0.333 * TD[b]
TDI = TD + IND
CONT = 0.20 * TDI
LAND[c] = $4000 pulverized coal boilers
= $2000 all other boilers
WC = 0.25 * (TDOM - Fuel) + 0.0833 (Fuel)[d]
TOTL = TK + LAND + WC

2. Operation and Maintenance Costs

FUEL = CF * Q * FC * 8760
TDOM = Sum of all O&M Costs other than OH
OH = 0.30 * DL + 0.26 * (DL + SPRV + MANT + SP)
TOTL = TDOM + OH

3. Annualized Costs

CR = CRF * TK
WCC = 0.10 * WC
MISC = 0.04 * TK
TCC = CR + WCC + MISC
TOTL = TCC + TOTL O&M Costs

---

[a] FGD system cost algorithms compute TD without prior computation of EQUP and INST.

[b] Some algorithms compute IND explicitly as a function of boiler and/or control device specifications.

[c] Only boilers have costs assumed for land.

[d] For boilers, assume a 3-month supply of all working capital components except fuel which will have a 1-month supply. For control devices, working capital is 25 percent of total direct operating and maintenance costs.

TABLE B-3. SAMPLE OUTPUT: IBCOST

```
S STAR (METRIC)=      1.072
S DSTAR (METRIC)=   452.296
   BOILER ROUTINE= PLVR      SO2 ROUTINE= DA
   PM ROUTINE=           NOX ROUTINE= LEA

   MALF= YES      MONT= YES       MAXFUEL= NO

BOILER SPECIFICATIONS
   Q=  400.0     FLW=       141399.     CF=   .600
FUEL SPECIFICATIONS
   FC=   2.24   H=   11660.   S=   3.23   A=  12.00
   FN=    .00   REG= REG V        FTYP= H-BIT
PM SPECIFICATIONS
   UNCPM=  4.374     CTRPM=  4.374     EFFPM=     .00
SO2 SPECIFICATIONS
   UNCSO2=  5.540     CTRSO2=   .554     EFFSO2=  90.00REL= 95.00     NGP=   3.77
NOX SPECIFICATIONS
   FFAC= 9820.     UNCEA= 50.0     CTREA= 35.0     DELT=     .0
FBC SPECIFICATIONS
   FCS=   .000
COST RATES
   DLR=  18.15     SLR=  23.60   AMLR=  22.09   ELEC=  .0390   WTR=   .230
   ALIME=  53.00   ALS=  12.00   SASH= 136.00   SLDG=  23.00   SWD=  23.00
   ALWD=   .600
ECONOMIC SPECIFICATIONS
   BCRF=  .1315     CRFSO2=  .1315     CRFPM=  .1315     CRFNOX=  .1315
   CAPCM=  1.030     AOMCM=  1.030        FUELM=  1.000       AYEAR= MAR 85

COST TABLE - RUN NO.      1  ($1000)
-----------------------------------------------------------------------
ITEM   BOILER              NOX              SO2             PM           TOTAL
-----------------------------------------------------------------------

EQUP          10855.           37.             0.             0.         10892.
INST           5808.           14.             0.             0.          5822.
TD            16663.           51.          2021.             0.         18735.
IND            5211.            0.             0.             0.          5211.
TDI           21874.           51.             0.             0.         21925.
CONT           4375.           10.             0.             0.          4385.
TK            26249.           62.          3184.             0.         29494.
LAND              6.            0.             0.             0.             6.
WC              945.           -3.           271.             0.          1213.
MONT            113.           59.             1.             0.           173.
IDC            3150.            7.           436.             0.          3593.
TOTL          30463.          125.          3892.             0.         34480.

DL              633.            0.           123.             0.           756.
SPRV            172.            0.            24.             0.           196.
MANT            335.            0.           127.             0.           462.
SP              409.            3.             0.             0.           412.
ELEC            540.            0.            41.             0.           581.
UC                0.            0.             0.             0.             0.
WTR              79.            0.             4.             0.            84.
SW               44.            0.             0.             0.            44.
SLDG              0.            0.           479.             0.           479.
LW                0.            0.             0.             0.             0.
SC                0.            0.            55.             0.            55.
LMS               0.            0.             0.             0.             0.
LIME              0.            0.           230.             0.           230.
FUEL           4709.          -44.             0.             0.          4666.
TDOM           6921.          -40.          1083.             0.          7964.
OH              592.            1.           108.             0.           701.
MONT             54.           37.            40.             0.           131.
TOTL           7567.           -2.          1231.             0.          8796.

CR             3866.            9.           476.             0.          4351.
WCC              95.            0.            27.             0.           121.
MISC           1050.            2.           127.             0.          1180.
TCC            5010.           11.           630.             0.          5652.
MONT             68.           45.            40.             0.           154.
TOTL          12592.           17.          1862.             0.         14471.

     TOTAL ANNUALIZED COSTS INCLUDING MALFUNCTION COSTS  14632.
```

TABLE B-4. SAMPLE OUTPUT: RCUCM

```
Input Data Summary, Run No.  1, Algorithm LWSU          00-00-00

Data Block RATE     COST RATES
-------------------------------------------------------------------
DLR    2  DIRECT LABOR RATE ($/M-HR)                          18.150
ELEC   2  ELEC RATE ($/KW-HR)                                   .039
STM    2  STEAM RATE ($/1000 LB)                               5.000
ALS    2  LIMESTONE RATE ($/TON)                              12.000
FOIL   0  FUEL OIL RATE ($/GAL)                                 .000

Data Block BLRS     BLR SPECIFICATIONS
-------------------------------------------------------------------
BTYP   2  BOILER TYPE (1.=PC,2.=SS,3.=MF)                      1.000
QUMW   2  UTILITY CAPACITY (MW)                              200.000
Q      2  HEAT INP CAPACITY (MMBTU/HR)                      2000.000
FLW    1  FLUE GAS FLOWRATE (ACFM)                        708723.000
EFF    2  BOILER EFFICIENCY (PERCENT)                           .850
HROV   1  UTIL OVERALL HEAT RATE (BTU/KWH)                932881.300
ELEV   1  UTIL SITE ELEVATION (FT MSL)                          .000
CF     2  CAPACITY FACTOR (-)                                   .600
HRST   1  UTIL STM CYCLE HEAT RATE (BTU/KWH)                7924.000

Data Block FUEL     FUEL SPECIFICATIONS
-------------------------------------------------------------------
H      2  HEATING VALUE (BTU/LB)                           11660.000
S      2  SULFUR CONTENT (PERCENT)                             3.230
FTYP   2  FUEL TYPE (1.=EB,2.=WB,3.=LGN,4.=ANTH)               1.000

Data Block SO2      SO2 EMISSION DATA
-------------------------------------------------------------------
UNCS   2  UNCONTROLLED SO2 EMISSIONS (LB/MMBTU)                5.263
CTRS   2  CONTROLLED SO2 EMISSIONS (LB/MMBTU)                   .526
EFFS   2  SO2 CONTROL EFFICIENCY (PERCENT)                    90.000
BYPS   2  BYPASS SYSTEM (1.=NO,2.=YES)?                        1.000
RHTS   2  REHEAT SYSTEM (1.=NO,2.=YES)?                        1.000

Data Block ECON     ECONOMIC FACTORS
-------------------------------------------------------------------
RFER   2  REAL FUEL ESCALATION RATE (PRCT/YR)                   .000
ROER   0  REAL OM ESCALATION RATE (PRCT/YR)                     .000
INFR   2  INFLATION RATE (PRCT/YR)                             5.000
DISC   2  DISCOUNT RATE/COST OF MONEY (PRCT/YR)               10.000
ROE    2  RETURN ON EQUITY (PRCT/YR)                          15.000
ROD    2  RETURN ON DEBT (PRCT/YR)                            15.000
DEBT   2  AMOUNT DEBT FINANCED (PERCENT)                      50.000
ANPE   2  ANALYSIS PERIOD/EQUIPMENT LIFE (YRS)                20.000
ACRS   2  TAX EQUIP LIFE (1.=3,2.=5,3.=10,4.=15)               4.000
AITR   2  COMBINED (ST/FED) TAX RATE (PRCT/YR)                50.000
CPER   2  CONSTRUCTION PERIOD (MONTHS)                        24.000
UF     2  UPDATE FACTOR (USE 1.0 FOR NO UPDATE)                1.343

Algorithm Level Cost Results, Run No.  1, Algorithm LWSU          00-00-00
Capital Costs
     TOTAL PLANT COST     =     55206820.
     INTR DURING CONSTR   =      9033137.
     START UP AND MODIF   =      2760341.
```

TABLE B-4. SAMPLE OUTPUT: RCUCM (Continued)

```
      TOTAL DEPREC INVST    =     67000300.
      WORKING CAPITAL       =      2093664.
      TOTAL CAPITAL INVST   =     69093960.
 Operation and Maintenance Costs
      DIRECT LABOR          =       918173.
      SUPERVISION LABOR     =       137726.
      MAINTENANCE LABOR     =      1509975.
      SPARE PARTS           =      1509975.
      ELECTRICITY           =       680868.
      LIMESTONE             =       601129.
      TOTAL DIRECT O&M      =      5357847.
      OVERHEAD              =      2301899.
      TOTAL O&M             =      7659746.

Life Cycle Analysis of Algorithm Level Costs, Run No.  1, Algorithm LWBU        00-00-00
------------------------------------------------------------------------------------------------
 Yr          O and M                              Capital Charges                      Year Total
       ----------------------- -----------------------------------------------------------
        Fuel          Other        ROE          ROD          Depr        Inc Tax      Ins/PT
------------------------------------------------------------------------------------------------

  1            0.     8042733.     5182047.     5182047.     3350015.    -6208003.     2418289.    17967130.
  2            0.     8444869.     4930796.     4930796.     3350015.     1580781.     2418289.    25655540.
  3            0.     8867112.     4679545.     4679545.     3350015.     1999533.     2418289.    25994030.
  4            0.     9310468.     4428294.     4428294.     3350015.     2418285.     2418289.    26353640.
  5            0.     9775990.     4177042.     4177042.     3350015.     2837037.     2418289.    26735410.
  6            0.    10264790.     3925791.     3925791.     3350015.     3255788.     2418289.    27140460.
  7            0.    10778030.     3674540.     3674540.     3350015.     3004537.     2418289.    26899950.
  8            0.    11316930.     3423289.     3423289.     3350015.     2753286.     2418289.    26685090.
  9            0.    11882780.     3172038.     3172038.     3350015.     2502035.     2418289.    26497190.
 10            0.    12476910.     2920786.     2920786.     3350015.     2920786.     2418289.    27007570.
 11            0.    13100760.     2669535.     2669535.     3350015.     2669535.     2418289.    26877060.
 12            0.    13755800.     2418284.     2418284.     3350015.     2418284.     2418289.    26778950.
 13            0.    14443590.     2167033.     2167033.     3350015.     2167033.     2418289.    26712990.
 14            0.    15165760.     1915782.     1915782.     3350015.     1915782.     2418289.    26681410.
 15            0.    15924050.     1664531.     1664531.     3350015.     1664531.     2418289.    26685940.
 16            0.    16720250.     1413280.     1413280.     3350015.     4763295.     2418289.    30078410.
 17            0.    17556260.     1162029.     1162029.     3350015.     4512044.     2418289.    30160670.
 18            0.    18434080.      910778.      910778.     3350015.     4260792.     2418289.    30284730.
 19            0.    19355780.      659526.      659526.     3350015.     4009541.     2418289.    30452680.
 20            0.    20323570.      408275.      408275.     3350015.     3758290.     2418289.    30666710.

Totals
Abs            0.   265940500.    55903220.    55903220.    67000300.    49203180.    48365760.   542316200.
PW             0.    97414200.    30196640.    30196640.    28520560.    14576360.    20588250.   221492800.
Lev            0.    11442240.     3546886.     3546886.     3350014.     1712134.     2418288.    26016440.
```